U.S. DEPARTMENT OF COMMERCE
National Technical Information Service

PB-267 659

Revision of Evaporative Hydrocarbon Emission Factors

Radian Corp, Austin, Tex

Prepared for

Environmental Protection Agency, Research Triangle Park, N C Monitoring and Data Analysis Div

Aug 76

B 267 659

EPA-450/3-76-039
August 1976

REVISION OF EVAPORATIVE HYDROCARBON EMISSION FACTORS

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Air and Waste Management
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

REPRODUCED BY
NATIONAL TECHNICAL
INFORMATION SERVICE
U.S. DEPARTMENT OF COMMERCE
SPRINGFIELD, VA. 22161

TECHNICAL REPORT DATA

(Please read Instructions on the reverse before completing)

1. REPORT NO. EPA-450/3-76-039	2.	3. RECIPIENT'S ACCESSION NO.
4. TITLE AND SUBTITLE Revision of Evaporative Hydrocarbon Emission Factors		5. REPORT DATE August 1976 6. PERFORMING ORGANIZATION CODE
7. AUTHOR(S) C. E. Burklin and R. L. Honerkamp		8. PERFORMING ORGANIZATION REPORT NO. 100-086-01
9. PERFORMING ORGANIZATION NAME AND ADDRESS Radian Corporation 8500 Shoal Creek Blvd. P. O. Box 9948 Austin, Texas 78766		10. PROGRAM ELEMENT NO. 11. CONTRACT/GRANT NO. 68-02-1889
12. SPONSORING AGENCY NAME AND ADDRESS U.S. Environmental Protection Agency Office of Air Quality Planning and Standards Monitoring and Data Analysis Division Research Triangle Park, North Carolina 27711		13. TYPE OF REPORT AND PERIOD COVERED Final Report 14. SPONSORING AGENCY CODE

15. SUPPLEMENTARY NOTES

16. ABSTRACT

The increased use of EPA Document AP-42 entitled Compilation of Air Pollutant Emission Factors and EPA's National Emission Data System (NEDS) have brought to light a need to improve the emission factors pertaining to evaporative hydrocarbon losses from the petroleum industry. As defined for this program, the petroleum industry comprises production, transportation, storage, refining, and marketing operations for petroleum crude oil and petroleum products.

This report presents the work performed to update and revise the information presently contained in the EPA Document AP-42 Compilation of Air Pollutant Emission Factors related to evaporative hydrocarbon emissions from the petroleum industry.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Source Classification Codes Emissions HC RVP		

18. DISTRIBUTION STATEMENT Release Unlimited	19. SECURITY CLASS *(This Report)* Unclassified	21. NO. OF PAGES 130
	20. SECURITY CLASS *(This page)* Unclassified	22. PRICE PCA07-A01

EPA Form 2220-1 (9-73)

EPA-450/3-76-039

REVISION OF EVAPORATIVE HYDROCARBON EMISSION FACTORS

by

C.E. Burklin and R.L. Honerkamp

Radian Corporation
8500 Shoal Creek Blvd.
P.O. Box 9948
Austin, Texas 78766

Contract No. 68-02-1889
(Radian No. 100-086-01)

EPA Project Officer: Charles C. Masser

Prepared for

ENVIRONMENTAL PROTECTION AGENCY
Office of Air and Waste Management
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

August 1976

ia

This report is issued by the Environmental Protection Agency to report technical data of interest to a limited number of readers. Copies are available free of charge to Federal employees, current contractors and grantees, and nonprofit organizations - in limited quantities - from the Library Services Office (MD-35), Research Triangle Park, North Carolina 27711; or, for a fee, from the National Technical Information Service, 5285 Port Royal Road, Springfield, Virginia 22161.

This report was furnished to the Environmental Protection Agency by Radian Corporation, 8500 Shoal Creek Blvd., P.O. Box 9948, Austin, Texas 78766, in fulfillment of Contract No. 68-02-1889 (Radian No. 100-086-01). The contents of this report are reproduced herein as received from Radian Corporation. The opinions, findings, and conclusions expressed are those of the author and not necessarily those of the Environmental Protection Agency. Mention of company or product names is not to be considered as an endorsement by the Environmental Protection Agency.

Publication No. EPA-450/3-76-039

ABSTRACT

The increased use of EPA Document AP-42 entitled Compilation of Air Pollutant Emission Factors and EPA's National Emission Data System (NEDS) have brought to light several inadequacies in the information contained in these sources pertaining to evaporative hydrocarbon losses from the petroleum industry. This report presents the work performed by Radian in EPA study 68-02-1889 to update and revise the information presently contained in the National Emissions Data System and the EPA Document AP-42 Compilation of Air Pollutant Emission Factors related to evaporative hydrocarbon emissions from the petroleum industry. As defined for this program, the petroleum industry comprises production, transportation, storage, refining, and marketing operations for petroleum crude oil and petroleum products. The methodologies used to make these revisions are also presented. A discussion of the merits of conducting source testing and an outline of a source test program for evaporative emission sources when further source testing is warranted is included in the last section of this report.

TABLE OF CONTENTS

Page

1.0 INTRODUCTION 1

2.0 REVISIONS TO AP-42 2
  2.1 Storage Losses 2
    2.1.1 Hydrocarbon Properties 2
    2.1.2 Clarification of Storage Losses 4
    2.1.3 Revisions to Loss Correlations . 5
    2.1.4 Revised Emission Factors for Storage Losses 7
  2.2 Transportation and Marketing Losses . . 8
    2.2.1 Clarification of Transportation and Marketing Losses 8
    2.2.2 Revisions to Loss Correlations . 8
  2.3 Refinery Losses 11
  2.4 Production Losses 12
  2.5 Crude Oil RVP's 13

3.0 REVIEW OF SOURCE CLASSIFICATION CODES . . . 14

4.0 TEST PLAN DEVELOPMENT 16
  4.1 Storage - Bulk 16
  4.2 Storage - Service Stations 20
  4.3 Loading - Bulk 20
  4.4 Loading - Service Station 22
  4.5 Natural Gas and Crude Oil Production . 23
  4.6 Refinery - Fugitive 25
  4.7 Refinery - Process 26
  4.8 Transportation 26
  4.9 Vapor Characteristics 27

TABLE OF CONTENTS (Cont.)

Page

ATTACHMENT A: STORAGE LOSSES 29

ATTACHMENT B: TRANSPORTATION AND LOADING LOSSES 57

ATTACHMENT C: REFINERY LOSSES 77

ATTACHMENT D: PRODUCTION LOSSES 83

ATTACHMENT E: SOURCE CLASSIFICATION CODES 109

LIST OF TABLES

Page

TABLE 4.0-1 Characterization of Evaporative Hydrocarbons by Industry 17

TABLE 4.0-2 Characterization of Evaporative Hydrocarbons by Source 18

1.0 INTRODUCTION

The increased use of EPA Document AP-42 entitled Compilation of Air Pollutant Emission Factors and EPA's National Emission Data System (NEDS) have brought to light several inadequacies in the information contained in these sources pertaining to evaporative hydrocarbon losses from the petroleum industry.

Radian Corporation was contracted by EPA to upgrade and refine the information presently contained in AP-42 and the NEDS, related to evaporative hydrocarbon emission from the petroleum industry. As defined for this program, the petroleum industry comprises production, transportation, storage, refining, and marketing operations for petroleum crude oil and petroleum products. Specific items reviewed by Radian include:

- the vapor properties of hydrocarbon fuels,
- the definitions for terms and equations,
- the utility of equations and their units, and
- the comprehensiveness of correlations and factors.

Radian was also contracted as part of this study to develop a test plan for conducting source testing where further testing is warranted.

This report presents the work performed by Radian in EPA study 68-02-1889 to update and revise the information presently contained in the National Emissions Data System and the EPA Document AP-42 Compilation of Air Pollutant Emission Factors related to evaporative hydrocarbon emissions from the petroleum industry. The methodologies used to make these revisions are also presented. A discussion of the merits of conducting source testing and an outline of a source test program for evaporative emission sources when further source testing is warranted, is included in the last section of this report.

2.0 REVISIONS TO AP-42

Radian's revisions to the evaporative loss section of EPA document AP-42 entitled Compilation of Air Pollutant Emission Factors, and the methodologies used in making these revisions are presented in this section. AP-42 is an EPA document which discusses sources of air emissions, available control technologies, and emission rates. The portions of AP-42 which were revised in this study are those pertaining to evaporative hydrocarbon losses from the petroleum industry. Evaporative losses from petroleum storage and transportation are currently presented in Sections 4.3 and 4.4 respectively of Supplement No. 1 to AP-42. Evaporation losses from petroleum refining are currently presented in Section 9.1 of AP-42. No emissions are currently presented in AP-42 for evaporative emissions from petroleum production operations.

2.1 Storage Losses

The revised Section 4.3 of AP-42 pertaining to storage losses is presented in Attachment A. These revisions include improved data on the properties of hydrocarbon liquids and their vapors, restructured equations for calculating losses from petroleum storage, expanded descriptions of petroleum storage losses and of the use of the loss equations, and revised emission factors.

2.1.1 Hydrocarbon Properties

The physical properties of crude oil and petroleum fuels presented in Section 4.3 and 4.4 of AP-42 were found to be deficient and partially incorrect. The following problems were identified with the data on the physical properties of hydrocarbon fuels:

(1) Molecular weights for the vapors of petroleum fuels were too low.

(2) Incomplete data were given on the density of petroleum liquids.

(3) Incomplete data were given on the density of condensed vapors from petroleum fuels.

(4) No direct correlations were given for vapor pressure vs. temperature for either petroleum fuels, petroleum products, or various crude oils.

In the revised Section 4.3 on storage losses, Radian added Figures 4.3-8 and 4.3-9 which present nomographs for the calculation of true vapor pressures for crude oil and gasolines. These nomographs are taken from API Bulletin 2513 on Evaporation Loss in the Petroleum Industry. The temperature and RVP of a crude oil or gasoline can be used to obtain the true vapor pressure of the liquid using these nomographs.

Radian also developed Table 4.3-3 which presents the densities of petroleum liquids, the molecular weights and liquid densities of the vapors from petroleum liquids, and the vapor pressures of petroleum liquids at seven commonly encountered temperatures. This information was primarily obtained from API bulletin 2513 and from NACA Technical Note 3276 on Properties of Aircraft Fuels. The vapor pressure data developed for fuels were compared with data collected by EPA and were found to agree quite well.

2.1.2 Clarification of Storage Losses

The descriptions and explanations presented in Section 4.3 on storage losses were expanded where necessary to clarify sources of storage losses and the proper application of correlations for calculating storage losses. In several instances it was not clear in the description of variables for an equation whether the molecular weight input required by the equation was that of the vapor or of the liquid. Because properties for the vapors of fuels differ significantly from the properties of the fuels themselves, the terms used in the storage loss correlations were defined more clearly.

Variables used in the storage loss equations and their units were also changed to conform to convention and to standardize the variables used among all of the evaporative loss equations. The units used in the revised storage loss correlations were those units expected to be most convenient for persons employing AP-42.

Radian expanded the scope of AP-42 by including the API correlation for calculating withdrawal losses from floating roof tanks storing gasoline.

An example calculation was included in the revised storage loss section to demonstrate the proper method of applying the storage loss equations. It is hoped that better understanding of how to apply the storage loss equations will lead to increased use of the equations over the use of the less accurate storage loss factors.

2.1.3 Revisions to Loss Correlations

The correlations currently used in AP-42 for calculating storage losses are based on API studies. Each of these equations is designed for calculating hydrocarbon emissions from gasoline storage. Emissions from the storage of crude oil and other petroleum products are calculated using the gasoline specific equations and by multiplying the results from that equation by an adjustment equation. The adjustment equation developed by API is presented in API Bulletin 2523 and is of the form;

$$L = \left(\frac{0.08M}{d}\right) L_G$$

where

L = liquid volume of vapors lost (bbl)
M = molecular weight of vapors lost
d = liquid density of vapors lost (lb/gal)
L_G = liquid volume of vapors lost as calculated by the gasoline specific equation (bbl)

It should be noted that $\frac{d}{M}$ for gasoline is roughly 0.08, and the constant 0.08 is used in the adjustment equation to cancel the value of $\frac{M}{d}$ for gasoline out of the gasoline specific equation.

Radian combined the adjustment equation with the gasoline specific loss equations to form a single universal equation. As an example, the fixed roof tank breathing loss equation for gasoline storage is of the form:

$$L_G = 0.024 \left[\frac{P}{14.7-P}\right]^{0.68} D^{1.73} H^{0.51} \Delta T^{0.50} F_P C K_c$$

where L_G = fixed roof breathing loss for gasoline (bbl/yr)

P = True vapor pressure of liquid at bulk liquid temperature (psia)
D = Tank diameter (ft)
H = Average vapor space height (ft)
ΔT = Average diurnal temperature change (°F)
F_p = Paint factor
C = Adjustment factor for small diameter tanks
K_c = Adjustment factor for crude oil storage

Application of the adjustment equation yields,

$$L = \frac{0.08M}{d} (0.024) \left[\frac{P}{14.7-P}\right]^{0.68} D^{1.73} H^{0.51} \Delta T^{0.50} F_p \, C \, K_c$$

or;

$$L = 0.00192 \frac{M}{d} \left[\frac{P}{14.7-P}\right]^{0.68} D^{1.73} H^{0.51} \Delta T^{0.50} F_p \, C \, K_c$$

Multiplying the equation by $\frac{42d}{365} \left(\frac{\text{lb-yr}}{\text{bbl-day}}\right)$ the units of the equation become pounds per day and;

$$L = 2.21\text{x}10^{-4} M \left[\frac{P}{14.7-P}\right]^{0.68} D^{1.73} H^{0.51} \Delta T^{0.50} F_p \, C \, K_c$$

The above equation is universally applicable to gasoline storage, crude oil storage, and the storage of all other petroleum products with vapor pressures in the range of gasoline vapor pressures. When this equation is applied to the storage of gasoline with a $\frac{d}{M}$ ratio of 0.08 it yields the exact same value as the preceding gasoling specific equation.

The other gasoline specific equations for storage losses presented in AP-42 were restructured in a similar manner to yield single universal equations which are applicable to the storage of gasoline, crude oil, and petroleum products.

The API only recommends the use of these storage loss equations for cases in which the stored petroleum liquids exhibit vapor pressures in the same range as gasolines. However, in the absence of any correlations developed specifically for naphthas, kerosenes, or fuel oils it is recommended that the API storage loss equations also be used for the storage of these heavier fuels.

2.1.4 Revised Emission Factors for Storage Losses

Section 4.3 of AP-42 contains a table of emission factors for estimating emissions from petroleum liquid storage when sufficient information is not available for using the more accurate storage loss correlations. The emission factors for crude oil, JP-4, jet kerosene, and distillate were based on 50,000 bbl storage tanks. All other factors were based on 67,000 bbl storage tanks. Because tank size has a significant impact on storage emissions and because fuels are often stored in tanks larger than 100,000 bbl, a second set of factors was added to the storage loss factor table which are based on storage tanks with a capacity of 250,000 bbl. The second set of factors was added for crude oil and petroleum fuels storage only, as petrochemicals are primarily stored in the smaller tanks.

In addition to adding a set of factors based on larger storage tanks, each factor in the storage loss factor table was recalculated using the revised physical properties for petroleum liquids. Several factors were changed significantly.

The emission factors for storage losses are based upon typical systems and conditions. Radian emphasized in the revisions to AP-42 that these emission factors should only be used in the absence of sufficient parameters for using the more accurate emission correlations.

2.2 Transportation and Marketing Losses

The revised Section 4.4 of AP-42 on Transportation and Marketing Losses in the petroleum industry is presented in Attachment B. The major revisions to the transportation and marketing section centered around increased discussion of emission sources and simplification of the emission correlations.

2.2.1 Clarification of Transportation and Marketing Losses

The revised transportation and marketing loss section of AP-42 has a much expanded discussion on sources of hydrocarbon emissions, the mechanism by which these emissions are generated, and available emission control technology for hydrocarbon emission sources. Several figures were added to the descriptions for further clarification.

2.2.2 Revisions to Loss Correlations

Three problems surfaced when Radian investigated the emission rate correlations presented in Supplement No. 1 to AP-42 for evaporative hydrocarbon emissions from petroleum loading operations. Equations 1, 2, and 3 (reprinted below) were found to be specific for hydrocarbon blends with vapors exhibiting molecular weights in the same region as the molecular weight of gasoline vapors.

$$U_t = \frac{69{,}600\ YPW}{(690-4M)T} \qquad (1)$$

$$L_{sub} = \left(\frac{1-Y}{2}\right) \frac{69{,}600\ PW}{(690-4M)T} \qquad (2)$$

$$L_{sp} = \frac{1.02\times10^6 W}{(690-4M)T} \left[\frac{14.7-YP}{14.7-0.95P} -1\right] \qquad (3)$$

where,

U_t = unloading loss (lb/10^3gal)
L_{sub} = submerged loading loss (lb/10^3 gal)
L_{sp} = splash loading loss (lb/10^3gal)
Y = degree of saturation
P = true vapor pressure (psia)
W = liquid density (lb/gal)
T = temperature of liquid (°R)
M = molecular weight

The emission rate U_t, L_{sub}, or L_{sp} calculated by equations (1), (2), and (3) approaches infinity as the molecular weight (M) of the vapor approaches 172. API information also indicates that the term $\frac{1}{690-4M}$ was developed from gasoline test data only.

A second problem which surfaced when investigating equations (1), (2), and (3) is that each equation requires the input of a value for Y, the residual vapor's fractional approach to saturation. Residual vapors are those vapors remaining in the empty cargo tank from the previous delivery. Radian felt that most people resorting to the use of emission correlations will not have sufficient test data to supply a value for Y.

Finally, equations 4, 5 and 6 correlate mass emission rates with product density (W) and ignore the impact of temperature.

$$U_s = 0.07\ PW \quad \text{(unloading ships)} \qquad (4)$$

$$L_s = 0.08\ PW \quad \text{(loading ships)} \qquad (5)$$

$$R_s = 0.1\ PW \quad \text{(intransit loss on ships)} \qquad (6)$$

Where P = true vapor pressure (psia)
W = transported liquid density (lb/gal)
U_s, L_s, R_s = emission rate (lb/10^3gal)

The Ideal Gas law states that emission rates (on a weight basis) should be proportional to vapor molecular weight instead of liquid density and that emission rates should also be inversely proportional to temperature.

In an effort to simplify the calculation of loading emissions, equations 1 through 5 were restructured into a single equation based on the Ideal Gas law.

$$L_L = \frac{12.46\ SPM}{T}$$

Where L_L =Loading loss (lb/10^3gal)
P = True vapor pressure of the loaded hydrocarbon (psia).
M = Molecular weight of the vapors (lb/lb-mole)
T = Temperature of the liquid (°R).
S = Saturation factor.

The saturation factor (S) corrects for the fact that various loading methods result in the stratification of hydrocarbon vapors and in the expulsion of subsaturated vapors. A table of S factors was generated from API Bulletin 2514 on Evaporation Loss from Tank Cars, Tank Trucks, and Marine Vessels.

This equation based on the Ideal Gas law and on an S factor applies to loading losses from crude oil, gasoline, and petroleum products into truck, rail car, barge, and marine vessel modes of transportation.

The Ideal Gas law equation was not recommended for the calculation of hydrocarbon emissions from the marine loading of gasoline in light of the new marine operation emission factors recently released by the API. The API factors are more accurate than current information on S factors for marine loading of gasoline. The Ideal Gas law equation however is still recommended for the calculation of hydrocarbon emissions from the marine loading of crude oil and petroleum products other than gasoline.

Equation 6 of AP-42 pertaining to marine intransit losses was not restructured because sufficient information was not available for developing a value for the intransit loss S factor.

2.3 Refinery Losses

The revised Section 9.1 of AP-42 pertaining to Refinery Losses is presented in Attachment C. Revisions to the refinery loss section are limited to evaporative hydrocarbon emissions. Radian removed the evaporative hydrocarbon emission factors from Table 9.1-1 and formed them into a separate evaporative emission table (Table 9.1-2).

In an attempt to make the emission factors more useful, they are reported in several sets of units. For example, revised emission factors for evaporative emissions from process drains and waste water separators are given in the units of lbs/10^3 gallons of waste water and in the units of lbs/10^3bbl of refinery capacity. Revised pump seal leak rates are reported in lbs/day - seal and in lbs/10^3bbl refinery capacity. Table 9.1-2 also presents a separate set of evaporative emission factors for controlled emission sources.

Revisions to emission factors for sources other than evaporative emission sources were not within the scope of this program. This program also did not include revisions to the text of the refinery loss section of AP-42.

2.4 Production Losses

Section 9.3 concerning Evaporative Emissions from the petroleum production industry is a new section to AP-42 and not a revision to an existing section. To date, production emissions have not been covered in AP-42. The production loss section discusses in length the operations, emission sources, and available control technology for the petroleum production industry. As defined for Section 9.3, the petroleum production industry encompasses exploration, site preparation, drilling, crude oil processing, natural gas processing, and secondary or tertiary recovery.

While composing Section 9.3 it became apparent that very little definitive data is available on the emissions from the petroleum production industry. Although potentially very helpful as a description of the petroleum production industry and its evaporative emission sources, Section 9.3 is very weak in emission factors and correlations. Consequently, it may be premature to include a section on petroleum production emissions in AP-42 at this time.

2.5 Crude Oil RVP's

It had been suggested at the onset of this program that Radian incorporate a table into either Section 4.3 or Section 4.4 of AP-42 which listed the RVP's of the major crude oils of the world. After further study it was decided not to include such a table on crude oil RVP's for several reasons.

Currently there are in excess of fifty major crude oils imported into the United States. It is unlikely that many users of AP-42 will have information of sufficient detail to identify the specific crude oils about which he is concerned.

In those cases where the user of AP-42 does have information on the specific crude oils handled, it is also likely that he has access to crude oil assays performed by the refinery on the delivered crude oil. The physical properties reported in these assays are much more accurate than a table of well head assays because the volatility of crude oils is heavily dependent upon a very small quantity of light ends which have a tendency to weather significantly during transportation and handling.

3.0 REVIEW OF SOURCE CLASSIFICATION CODES

Source Classification Codes (SCC) were developed for the new evaporative emission factors and revised for the existing evaporative emission factors associated with the petroleum industy. A table of the revised codes is presented in Attachment E. The format and structure used in these revisions is identical to that appearing in the EPA publication NEDS Source Classification Codes, Appendix D of Supplement No. 5 (AP-42).

Symbols in the far right hand column of the Source Classification Code tables indicate the action taken to revise each code. These symbols represent the following actions:

Symbol	Action
*	No changes were made to the existing EPA SCC.
+	No changes were made to the newly added TACB (Texas Air Control Board) SCC.
1	Both the source title and emission factor were changed for an existing EPA SCC.
2	Both the source title and emission factor were changed for a newly added TACB SCC.
3	A new SCC was added.
4	Only the emission factor was changed for an existing EPA SCC.
5	Only the emission factor was changed for a newly added TACB SCC.

Although emission factors were developed for the storage of gasolines with three different vapor pressures, source classification codes were only assigned to the factors for the 10 RVP gasoline. The small increase in accuracy afforded by including emission factors for three gasolines and the infrequent demand for the factors for 7 RVP and 13 RVP gasolines did not justify the complexity resulting in the SCC system by including all three gasolines. Jet fuel in the existing SCC's was redefined as JP-4 and kerosene was redefined as jet kerosene.

No source classifications codes were assigned to petroleum production emissions because of their incompleteness. Neither were source classification codes assigned to refinery emission factors. It is anticipated that the refinery section of AP-42 will shortly undergo complete revision and it will be most efficient to revise all of the source classification codes for refinery emissions at one time.

4.0 TEST PLAN DEVELOPMENT

The increased use of EPA Document AP-42 entitled Compilation of Air Pollutant Emission Factors and EPA's National Emission Data System (NEDS) have brought to light several inadequacies in the information contained in these sources pertaining to evaporative hydrocarbon losses from the petroleum industry. Many emission factors in AP-42 work well when applied to a large cross section of sources but are inaccurate when applied to individual emission sources.

This section discusses the adequacy of the evaporative hydrocarbon emission factors currently contained in AP-42 and its Supplements. A discussion is also included on what would be involved in testing these sources. Tables 4.0-1 and 4.0-2 present a breakdown of the contribution of evaporative emission sources to the national hydrocarbon emission level. Table 4.0-2 also summarizes the adequacy of existing emission factors for these sources and the complexity of a sampling program to update these factors.

4.1 Storage - Bulk

The bulk storage of crude petroleum and petroleum products is the largest source of hydrocarbon emissions in the petroleum industry. Bulk storage operations contribute an estimated 7.4% of the nation's total hydrocarbon emissions. Even after the full application of best available emission control technology, storage emissions are expected to remain a very significant, if not the most significant, hydrocarbon emission source in the petroleum industry. The major contributor to hydrocarbon

TABLE 4.0-1

CHARACTERIZATION OF EVAPORATIVE HYDROCARBONS BY INDUSTRY

Industry	Evaporative Hydrocarbon Emissions (10^3 Ton/Year)	Percent of National Hydrocarbon Emissions
Natural Gas Production	544	2.1
Crude Oil Production	346	1.4
Crude Transportation	538	2.1
Refining	2101	8.3
Gasoline Marketing	1440	5.7
Refinery Product Marketing	257	1.0
TOTAL	5226	20.6

Sources

MSA Research Corporation, Hydrocarbon Pollutant Systems Study, Vol. 1. Stationary Sources, Effects and Control. PB-219-073, APTD 1499. Evans City, PA., 1972.

Burklin, C.E., et al., Control of Hydrocarbon Emissions from Petroleum Liquids. Contract No. 68-02-1319, Task 12, EPA 600/2-75-042. PB 246 650/ST. Austin, Texas, Radian Corporation, Sept. 1975.

TABLE 4.0-2

CHARACTERIZATION OF EVAPORATIVE HYDROCARBONS BY SOURCE

Source	Evaporative Hydrocarbon Emissions (10^3 Ton/Yr)	Percent of National Hydrocarbon Emissions	Emission Factor Accuracy	Involvement of Sampling Program
Storage - bulk	1890	7.4	uncertain	very involved
- service station	48	0.2	adequate	not necessary
Loading - bulk	426	1.7	not adequate	standard
- service station	872	3.4	not adequate	involved
Natural Gas Production	544	2.1	very poor	very involved
Crude Oil Production	344	1.4	very poor	very involved
Refinery - fugitive	857	3.4	not adequate	very involved
- process	243	1.0	uncertain	standard
Transportation	NA	NA	uncertain	standard
TOTAL	5224			

NA - data not available

Sources

MSA Research Corporation, Hydrocarbon Pollutant Systems Study, Vol. 1. Stationary Sources Effects and Control. PB-219-073, APTD 1499. Evans City, PA., 1972.

Burklin, C.E., et al., Control of Hydrocarbon Emissions from Petroleum Liquids. Contract No. 68-02-1319, Task 12, EPA 600/2-75-042. PB 246 650/ST. Austin, Texas, Radian Corporation, Sept. 1975 emissions from bulk storage operations is the bulk storage of gasoline both at refineries and in the gasoline marketing system.

The primary sources of hydrocarbon emission factors for bulk storage operations are the correlations derived by the Evaporative Loss Committee of API between 1959 and 1962. These correlations are based on testing results assembled by API from the petroleum industry. The reported accuracy of these correlations at the time of their development was estimated at ± 25% overall. There have been many significant developments made in recent years on storage tank design, especially in the area of seals for floating-roof tanks. It is likely that the API emission factor correlations do not adequately predict the hydrocarbon emissions from floating-roof tanks. Recent test results also indicate that API storage emission correlations do not adequately deal with petroleum liquids having low vapor pressures. Currently available floating-roof tank withdrawal loss correlations are limited to the use of gasoline storage only.

Because the accuracy of storage loss equations is unknown, it may be advisable to first conduct a screening study to identify areas where source testing is required. The screening study would review the basis for the present API storage loss equations and attempt to verify these equations by spot testing.

If a comprehensive sampling program is indicated by the screening study, elaborate testing procedures will have to be developed. Fixed-roof tank emission testing will be relatively straight forward. Care must be taken to record all applicable parameters. The hydrocarbon emission rate can be obtained by monitoring the vapors exiting the pressure/vacuum vent.

Measuring the hydrocarbon emission rate from floating-roof tanks is much more difficult. It is impossible to test floating-roof tank emissions by enclosing the tank because of its large size and the importance that wind velocity has on the emission rate. Floating-roof hydrocarbon emission testing will likely involve either ambient hydrocarbon sampling in the proximity of the tank and back calculating emission rates using diffusion modeling techniques or scale up of emission test results on small tanks. Several measurements must be taken around each tank and numerous tanks must be sampled to account for the effects of wind speed, tank size, seal type, fuel RVP, and temperature.

4.2 Storage - Service Stations

Existing emission factors for the storage of gasoline in underground service station tanks are adequate for the characterization of service station storage losses. The emission factors presented in AP-42 were developed in recent source testing programs on representative service station equipment. In addition, evaporation losses from service station storage tanks are small, contributing an estimated 0.2% of the nation's total hydrocarbon emissions. Even on the local level, service station storage losses are relatively small compared to vehicle refueling losses and bulk delivery losses.

4.3 Loading - Bulk

The bulk loading of crude petroleum and refined petroleum products into tank trucks, railcars, and marine vessels contributes an estimated 1.7% of the national hydrocarbon emissions. These loading losses are primarily attributable to gasoline loading operations within the gasoline marketing industry. Loading losses are even more significant on the local level because of the large quantities loaded at high loading rates on individual loading sites. Marine terminals load as much as 400 thousand gallons of gasoline per hour.

The correlations used today to calculate loading losses are largely based on loading loss correlations developed by the American Petroleum Institute in 1959. At that time they were estimated by API to have an overall accuracy of ± 35%. Since the development of loading loss correlation, there have not been dramatic changes in loading equipment. However, loading rates have increased and loading nozzles have been modified. Loading emission controls have also been improved. These design changes may have altered the applicability of the API loading loss correlations to current loading operations.

The API emission work concentrated on gasoline and crude oil loading operations into railcars and tank trucks. The correlations API developed have not been demonstrated to be accurate for the calculations of losses from the loading of other petroleum products or for the loading of gasoline and crude oil at nonstandard conditions. Marine and barge loading loss correlations were also inadequate, however API is currently in the process of revising these correlations.

Recent gasoline loading loss data for tank trucks has been collected in conjunction with studies to define the hydrocarbon emissions associated with the gasoline marketing industry. However, it appears that not enough parameters were measured to allow the development of a universal correlation for tank truck and railcar loading of crude oil and refined petroleum products.

Testing procedures for tank truck loading emissions have been developed in conjuncution with new source performance studies conducted on the gasoline marketing industry. These testing procedures are sufficient for the development of truck loading emission factors. Testing procedures for marine loading operations are similar to those for tank truck and railcar loading operations.

However, testing marine loading operations is more difficult because of the large flow rates and emission rates involved. A much larger scale of sampling equipment is required.

4.4 Loading - Service Station

Loading emissions at service stations include hydrocarbon emissions generated by the bulk drop of gasoline into the underground service station storage tank and the hydrocarbon emissions generated by refueling automobiles. Service station loading losses are estimated to contribute 3.4% of the national hydrocarbon emissions. Service station loading emissions are also significant when considered on the local level. The average service station emits an estimated 20 pounds of hydrocarbons per day at ground level. The hydrocarbon emission problem from service stations is further complicated by the high concentration of service stations in the average urban area.

Extensive source testing conducted in the past five years has resulted in the development of emission factors which adequately yield the hydrocarbon emission rate from national service station operations. These emission factors are most accurate when applied to a large cross section of service stations. Their accuracy may be a problem, however, when applied to individual sources. Scott Environmental Technology, Inc. developed a three-parameter correlation to calculate vehicle refueling emissions. Although the values predicted by the Scott correlation have been questioned, a correlation of this type is required to accurately calculate emissions from individual service stations or from service station operations conducted in a particular season or portion of the country. Sufficient test data may have been collected in recent studies to develop multi-parameter correlations for service station operations without the need for additional testing.

Adequate emission factors do not exist for service stations applying emission controls. Service station emission controls are currently a developing technology under a continued state of change. Biannual testing may be required to provide adequate up-to-date emission factors for controlled service station operations.

4.5 Natural Gas and Crude Oil Production

Although generally located in remote areas, the natural gas and crude oil production industry is a significant emission source. Collectively, emissions from the natural gas and crude oil production industry are estimated to represent 3.5% of the national hydrocarbon emissions.

Emission factors for the gas and oil production industry are not adequate. The primary source of emission factors for natural gas production operations is a Processes Research, Inc. report which based its emission estimates on the assumptions that: 1) all unaccounted natural gas is lost to the atmosphere, 2) twenty percent of the vented and flared gas is emitted without burning, and 3) emitted hydrocarbons have a density of 0.1 pounds per cubic foot. These assumptions require verification. Crude oil production emissions are largely based on a 1967 study conducted on crude oil production facilities in Monterey County by the Monterey-Santa Cruz County Unified APCD.

A broader study is required to verify the applicability of these emission factors to production facilities in all locations. The Santa Cruz study also did not include all of the hydrocarbon emission sources associated with production facilities. In addition there are no emission factors available for offshore production facilities. The uniqueness of offshore productions makes it inadvisable to apply onshore production emission factors to offshore operations.

Emission factors for production operations may need to be developed on two levels. On the first level, production emission factors would be developed which represent the average facility and which will be meaningful when applied to a large cross section of production facilities. These emission factors will be applicable to region-wide or state-wide emission inventories.

Because no production facility is average and because the range of production processing schemes is so great, average emission factors have no meaning for individual production facilities. A second set of equipment and process emission factors would be required for dealing with individual production facilities. If simple flow schemes are available for a production facility, emission factors for each piece of equipment can be assembled to yield an overall emission factor for that particular production facility.

A testing program for production facilities will be very involved. Although testing of direct process emissions will be straightforward, a large portion of the emissions from production operations are attributable to fugitive emission sources. Test procedures for fugitive emission sources will have to be developed. Both the development and implementation of fugitive emission source testing is a very involved process.

The development of emission factors for offshore production facilities must be a separate study. Emissions from offshore production facilities are expected to be unique. Most offshore production facilities are newer installations employing advanced processing and control technology. In addition, good housekeeping and maintenance practices are routinely employed as a safety measure. Fugitive leaks and spills present a great fire hazard to the high density of processing equipment on offshore production platforms.

4.6 Refinery - Fugitive

Fugitive emissions account for the major portion of hydrocarbon emissions from petroleum refining operations. It has been estimated that the fugitive hydrocarbon emissions from refinery operations contribute 3.4% of the nation's total hydrocarbon emissions.

The adequacy of current fugitive emission factors for refinery operations is unknown. These refinery emission factors were developed in the late 1950's in a survey of Los Angeles refineries. However, since the 1950's there have been many developments in processing and control technology for refineries. These developments have significantly changed the basis upon which the original refinery emission factors were derived.

The sampling of a petroleum refinery is a very involved task. Refineries are enormous processing complexes consisting of numerous fugitive emission sources. The task of establishing representative emission factors is further complicated by the wide variety of processing flow schemes used in petroleum refineries. Petroleum refineries range from simple topping facilities designed to separate crude oil into its basic natural components to a fully integrated gasoline and petrochemical refinery designed to alter the composition of crude oil constituents to maximize the production of gasoline and petrochemicals.

A suggested form for the fugitive emission factors for petroleum refineries is pounds/source-throughput and pounds/unit-throughput. For example fugitive emissions from pipeline valves on the atmospheric still might be expressed in units of pounds/valve-day and pounds/10^3bbl of atmospheric still throughput. The ability to account for the fugitive emissions from each unit according to unit size allows the calculation of fugitive emission rates which will be more accurate on the individual refinery level. It will remain impossible to account for variations in fugitive emissions due to variations in maintenance and housekeeping practices between refineries.

4.7 Refinery - Process

Although not as large as fugitive refinery emissions, process refinery emissions are a significant source of atmospheric hydrocarbons. It is estimated that process emissions account for 1% of the total national hydrocarbon emissions.

The adequacy of current emission factors for refinery process emissions is unknown. Most of the available process emission factors were originally developed in the late 1950's in a survey of Los Angeles refineries. Since that time some of these emission factors have been updated by the American Petroleum Institute and by the EPA. Because of the error uncertainty in process emission factors, screening tests should be conducted to identify sources for which detailed testing is warranted.

Process emission sources are generally fewer in number than fugitive emission sources and are much more easily identified. The sampling of process emission sources is much less involved than the sampling of fugitive emission sources.

4.8 Transportation

Very little data is available on the evaporative hydrocarbon emissions from transportation operations. The significance of these emissions has not been verified. Ship and barge intransit losses are probably significant owing to their consolidated large volume. Although dispersed in smaller cargoes, truck and rail intransit losses may also be significant. The testing of ship and barge transportation emissions would involve traveling with the vessel for a complete voyage. The vent lines on ships and barges are thought to be accessible. The sampling of tank trucks and rail tank cars is more difficult because of the limited space available for sampling equipment and lack of utilities.

4.9 Vapor Characteristics

Additional testing of vapor characteristics for common petroleum crude oils and refinery products is also warranted. Some testing has been conducted by API, however, the tests were conducted for different purposes and not all of the important parameters were tested. EPA has also conducted vapor pressure analysis for standard fuels, but these tests did not include sufficient data points in the ambient temperature range. In addition, more information must be collected on the molecular weights and condensed vapor densities of petroleum product vapors. These tests should include statistical analyses to select representative petroleum liquids. They should also focus on collecting the data in the full range of normal operating conditions.

ATTACHMENT A

STORAGE LOSSES

Preceding page blank

4.3 STORAGE OF PETROLEUM LIQUIDS

Fundamentally, the petroleum industry consists of three operations: (1) petroleum production and transportation, (2) petroleum refining, and (3) transportation and marketing of finished petroleum products. All three operations require some type of storage for petroleum liquids. Storage tanks for both crude and finished products can be sources of evaporative emissions. Figure 4.3-1 presents a schematic of the petroleum industry and its points of emissions from storage operations.

4.3.1 Process Description

Four basic tank designs are used for petroleum storage vessels: fixed roof, floating roof (open type and covered type), variable vapor space, and pressure (low and high).

Fixed Roof Tanks[3]

The minimum accepted standard for storage of volatile liquids is the fixed roof tank (Figure 4.3-2). It is usually the least expensive tank design to construct. Fixed roof tanks basically consist of a cylindrical steel shell topped by a coned roof having a minimum slope of 3/4 inches in 12 inches. Fixed roof tanks are generally equipped with a pressure/vacuum vent designed to contain minor vapor volume changes. For large fixed roof tanks, the recommended maximum operating pressure/vacuum is +0.03 psig/-0.03 psig (+2.1 g/cm^2/-2.1 g/cm^2).

Floating Roof Tanks[5]

Floating roof tanks reduce evaporative storage losses by minimizing vapor spaces. The tank consists of a welded or riveted cylindrical steel wall, equipped with a deck or roof

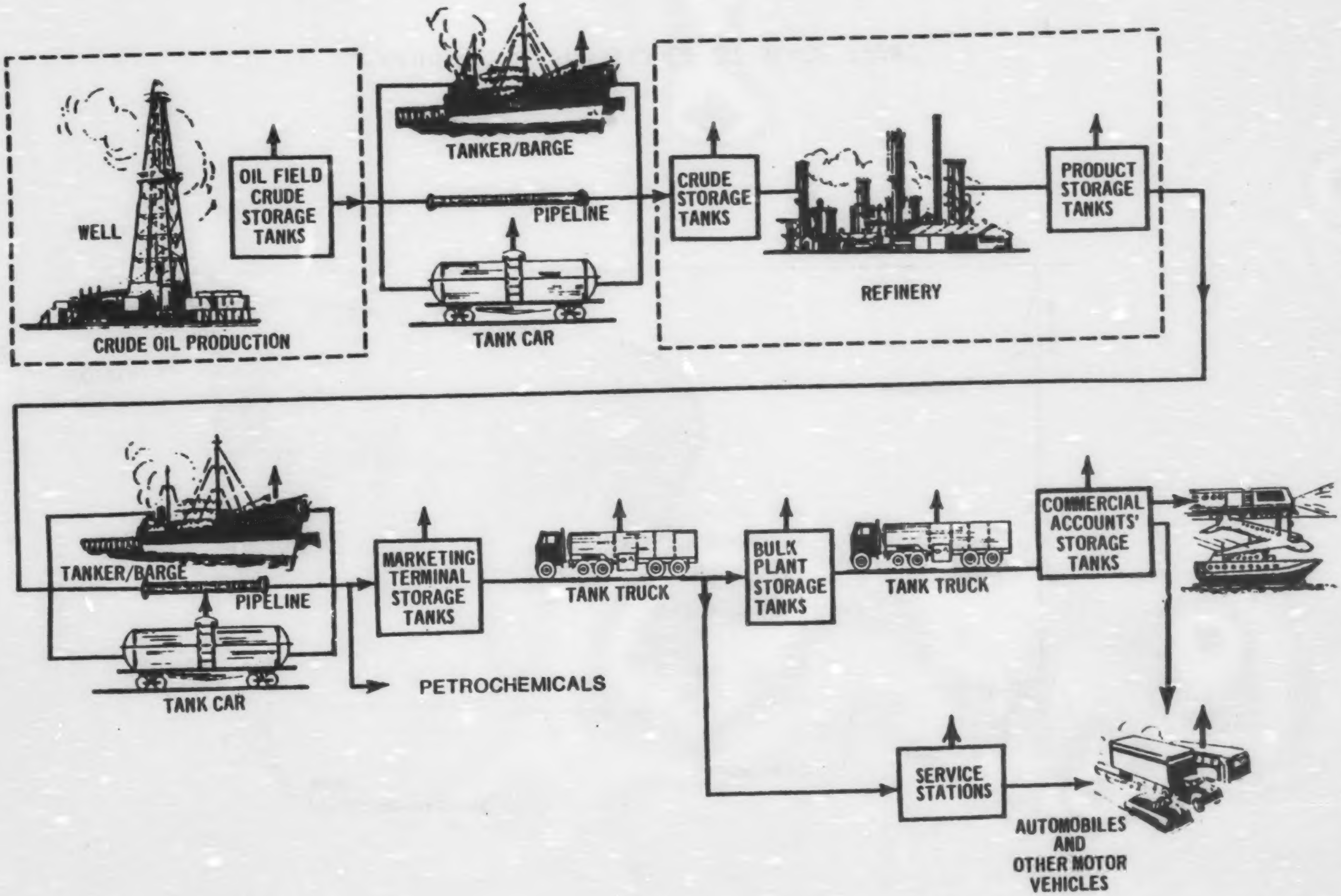

WELL
OIL FIELD CRUDE STORAGE TANKS
CRUDE OIL PRODUCTION
TANKER/BARGE
PIPELINE
TANK CAR
CRUDE STORAGE TANKS
REFINERY
PRODUCT STORAGE TANKS
TANKER/BARGE
PIPELINE
TANK CAR
PETROCHEMICALS
MARKETING TERMINAL STORAGE TANKS
TANK TRUCK
BULK PLANT STORAGE TANKS
TANK TRUCK
COMMERCIAL ACCOUNTS' STORAGE TANKS
SERVICE STATIONS
AUTOMOBILES AND OTHER MOTOR VEHICLES

Figure 4.3-1. Flowsheet of petroleum production, refining, and distribution systems. (Sources of organic evaporative emissions are indicated by vertical arrows).

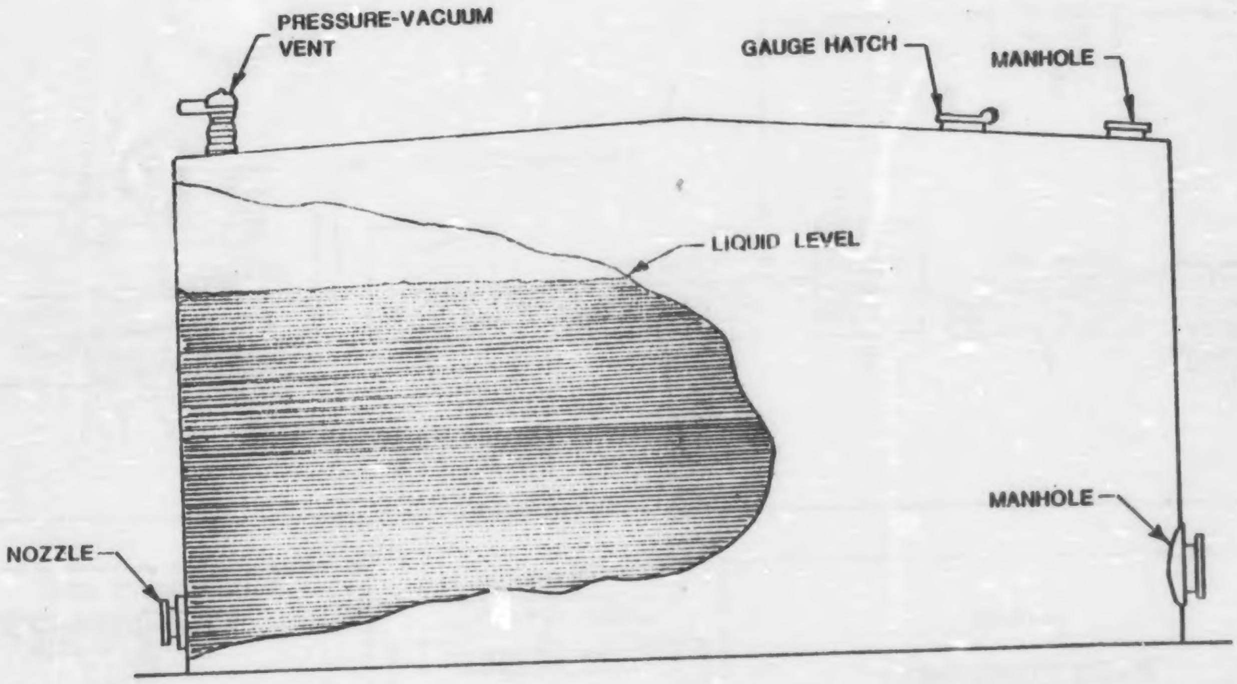

PRESSURE-VACUUM VENT
GAUGE HATCH
MANHOLE
LIQUID LEVEL
MANHOLE
NOZZLE

FIGURE 4.3-2. FIXED ROOF STORAGE TANK

which is free to float on the surface of the stored liquid. The roof then rises and falls according to the depth of stored liquid. To insure that the liquid surface is completely covered, the roof is equipped with a sliding seal which fits against the tank wall. Sliding seals are also provided at support columns and at all other points where tank appurtenances pass through the floating roof.

Until recent years, the most commonly used floating roof tank was the conventional open-type tank. The open-type floating roof tank exposes the roof deck to the weather; provisions must be made for rain water drainage, snow removal, and sliding seal dirt protection. Floating roof decks are of three general types; pan, pontoon, and double deck. The pan-type roof consists of flat metal plate with a vertical rim and sufficient stiffening braces to maintain rigidity (Figure 4.3-3). The single metal plate roof in contact with the liquid readily conducts solar heat, resulting in higher vaporization losses than other floating roof decks. The roof is equipped with automatic vents for pressure and vacuum release. The pontoon roof is a pan-type floating roof with pontoon sections added to the top of the deck around the rim. The pontoons are arranged to provide floating stability under heavy loads of water and snow. Evaporation losses due to solar heating are about the same as for pan-type roofs. Pressure/vacuum vents are required on pontoon roof tanks. The double deck roof is similar to a pan-type floating roof, but consists of a hollow double deck covering the entire surface of the roof, (Figure 4.3-4). The double deck adds rigidity, and the dead air space between the upper and lower deck provides significant insulation from solar heating. Pressure/vacuum vents are also required.

The covered-type floating roof tank is essentially a fixed-roof tank with a floating roof deck inside the tank

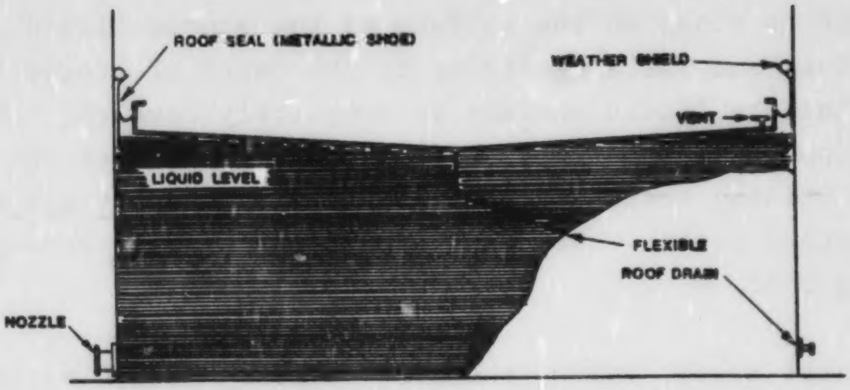

ROOF SEAL (METALLIC SHOE)
WEATHER SHIELD
VENT
LIQUID LEVEL
FLEXIBLE
ROOF DRAIN
NOZZLE

FIGURE 4.3-3. PAN-TYPE FLOATING ROOF STORAGE TANK (METALLIC SEALS)

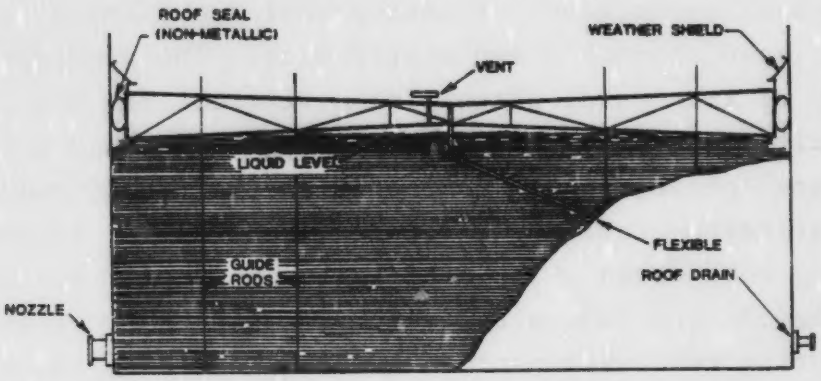

ROOF SEAL
(NON-METALLIC)
WEATHER SHIELD
VENT
LIQUID LEVEL
FLEXIBLE
ROOF DRAIN
GUIDE
RODS
NOZZLE

FIGURE 4.3-4. DOUBLE DECK FLOATING ROOF STORAGE TANK (NON-METALLIC SEALS)

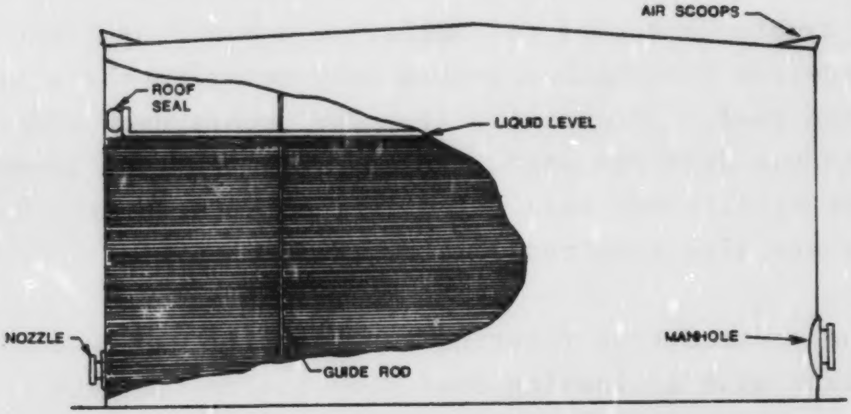

AIR SCOOPS
ROOF
SEAL
LIQUID LEVEL
NOZZLE
MANHOLE
GUIDE ROD

FIGURE 4.3-5. COVERED FLOATING ROOF STORAGE TANK

(Figure 4.3-5). The American Petroleum Institute has designated the term "covered floating " roof to describe a fixed roof tank with an internal steel pan-type floating roof. The term "internal floating cover" has been chosen by the API to describe internal covers constructed of materials other than steel. Floating roofs and covers can be installed inside existing fixed roof tanks. The fixed roof protects the floating roof from the weather, and no provision is necessary for rain or snow removal, or for seal protection. Antirotational guides must be provided to maintain roof alignment, and the space between the fixed and floating roofs must be vented to prevent the possible formation of a flammable mixture.

Variable Vapor Space Tanks[4]

Variable vapor space tanks are equipped with expandable vapor reservoirs to accommodate vapor volume fluctuations attributable to temperature and barometric pressure changes. Variable vapor space tanks are sometimes used independently, however, a variable vapor space tank is normally connected to the vapor spaces of one or more fixed roof tanks. The two most common types of variable vapor space tanks are lifter roof tanks and flexible diaphragm tanks.

Lifter roof tanks have a telescoping roof that fits loosely around the outside of the main tank wall. The space between the roof and the wall is closed by either a wet seal which consists of a trough filled with liquid, or a dry seal which employs a flexible coated fabric in place of the trough (Figure 4.3-6).

Flexible diaphragm tanks utilize flexible membranes to provide the expandable volume. They may be separate gasholder type units, or intergral units mounted atop fixed roof tanks (Figure 4.3-7).

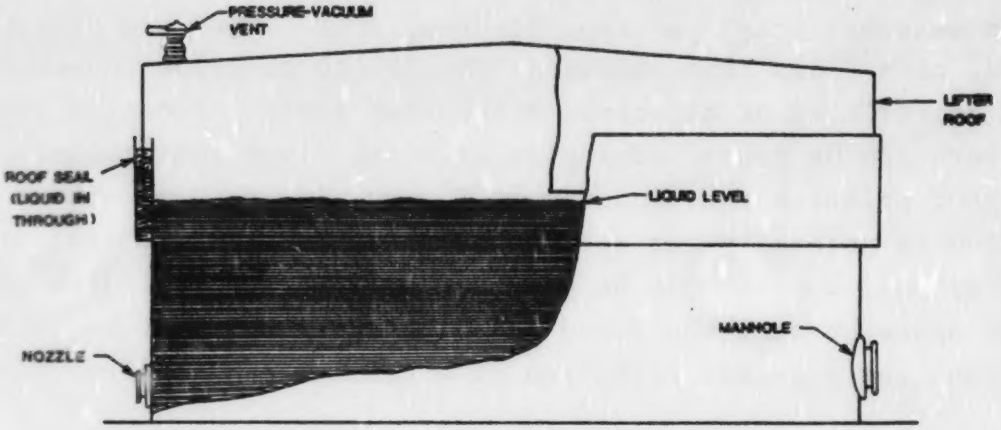

PRESSURE-VACUUM VENT
LIFTER ROOF
ROOF SEAL (LIQUID IN THROUGH)
LIQUID LEVEL
MANHOLE
NOZZLE

FIGURE 4.3-6. LIFTER ROOF STORAGE TANK (WET SEAL)

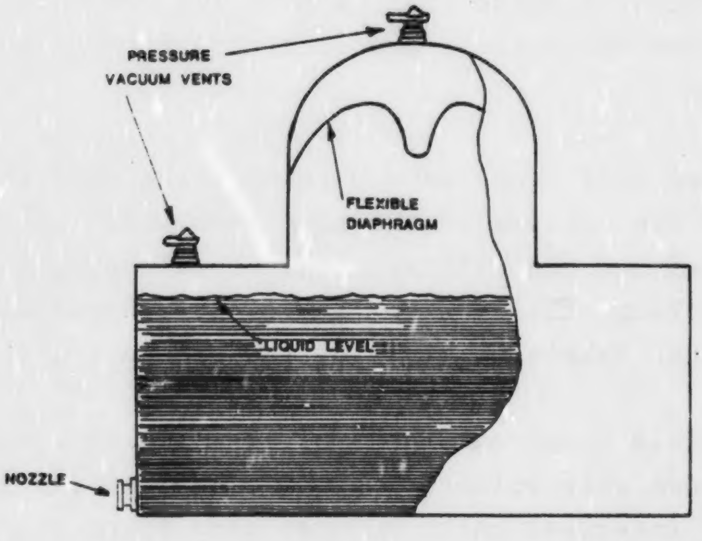

PRESSURE VACUUM VENTS
FLEXIBLE DIAPHRAGM
LIQUID LEVEL
NOZZLE

FIGURE 4.3-7. FLEXIBLE DIAPHRAGM TANK (INTEGRAL UNIT)

Pressure Tanks[6]

Pressure tanks are designed to withstand relatively large pressure variations without incurring a loss. They are generally used for storage of high volatility stocks, and they are constructed in many sizes and shapes, depending on the operating range. The noded spheroid and noded hemispheroid shapes are generally used as low pressure tanks (17 to 30 psia or 12 to 21 Mg/m^2), while the horizontal cylinder and spheroid shapes are generally used as high pressure tanks (up to 265 psia or 186 Mg/m^2).

4.3.2 Emissions and Controls

There are six sources of emissions from petroleum liquids in storage: fixed roof breathing losses, fixed roof working losses, floating roof standing storage losses, floating roof withdrawal losses, variable vapor space filling losses, and pressure tank losses.[2]

Fixed roof breathing losses consist of vapor expelled from a tank because of the thermal expansion of existing vapors, vapor expansion caused by barometric pressure changes, and/or an increase in the amount of vapor due to added vaporization in the absence of a liquid-level change.

Fixed roof working losses consist of vapor expelled from a tank as a result of filling or emptying operations. Filling loss is the result of vapor displacement by the input of liquid. Emptying loss is the expulsion of vapors subsequent to product withdrawal, and is attributable to vapor growth as the newly inhaled air is saturated with hydrocarbons.

Floating roof standing storage losses result from causes other than breathing or change in liquid level. The largest potential source of this loss is attributable to an improper fit of the seal and shoe to the shell, which exposes some liquid surface to the atmosphere. A small amount of vapor may escape between the flexible membrane seal and the roof.

Floating roof withdrawal losses result from evaporation of stock which wets the tank wall as the roof descends during emptying operations. This loss is small in comparison to other types of losses.

Variable vapor space filling losses result when vapor is displaced by the liquid input during filling operations. Since the variable vapor space tank has an expandable vapor storage capacity, this loss is not as large as the filling loss associated with fixed roof tanks. Loss of vapor occurs only when the vapor storage capacity of the tank is exceeded.

Pressure tank losses occur when the pressure inside the tank exceeds the design pressure of the tank, which results in relief vent opening. This happens only when the tank is filled improperly, or when abnormal vapor expansion occurs. These are not regularly occurring events, and pressure tanks are not a significant source of loss under normal operating conditions.

The total amount of evaporation loss from storage tanks depends upon the rate of loss and the period of time involved. Factors affecting the rate of loss include:

1) True vapor pressure of the liquid stored,
2) Temperature changes in the tank,
3) Height of the vapor space (tank outage),
4) Tank diameter,

5) Schedule of tank filling and emptying,
6) Mechanical condition of tank and seals,
7) Type of tank and type of paint applied to outer surface.

The American Petroleum Institute has developed empirical formulae, based on field testing, that correlate evaporative losses with the above factors and other specific storage factors.

Fixed Roof Tanks[1,3]

Fixed roof breathing losses can be estimated from:

$$L_B = 2.21 \times 10^{-4}\, M \left[\frac{P}{14.7-P}\right]^{0.68} D^{1.73}\, H^{0.51}\, \Delta T^{0.50}\, F_p\, C\, K_c \qquad (1)$$

where: L_B = Fixed roof breathing loss (lb/day).
M = Molecular weight of vapor in storage tank (lb/lb mole); see Table 4.3-3.
P = True vapor pressure at bulk liquid conditions (psia); see Figures 4.3-8, 4.3-9, or Table 4.3-3.
D = Tank diameter (ft).
H = Average vapor space height, including roof volume correction (ft); see note (1).
ΔT = Average ambient temperature change from day to night (^oF).
F_p = Paint factor (dimensionless); see Table 4.3-1.
C = Adjustment factor for small diameter tanks (dimensionless); see Figure 4.3-10.
K_c = Crude oil factor (dimensionless); see note (2).

Note: (1) The vapor space in a cone roof is equivalent in volume to a cylinder which has the same base diameter as the cone and is one-third the height of the cone.

(2) K_c = (0.65) for crude oil, K_c=(1.0) for gasoline and all other liquids.

API reports that calculated breathing loss from equation (1) may deviate in the order of ±10 percent from actual breathing loss.

Fixed roof working losses can be estimated from:

$$L_W = 2.40 \times 10^{-2} \, M \, P \, K_N \, K_c \qquad (2)$$

where L_W = Fixed roof working loss (lb/10^3 gal. throughput).
M = Molecular weight of vapor in storage tank (lb/lb mole); see Table 4.3-3.
P = True vapor pressure at bulk liquid conditions (psia); see Figures 4.3-8, 4.3-9, or Table 4.3-3.
K_N = Turnover factor (dimensionless); see Figure 4.3-11.
K_c = Crude oil factor (dimensionless); see note.

Note: K_c = (0.84) for crude oil, K_c = (1.0) for gasoline and all other liquids.

API reports that special tank operating conditions may result in actual losses which are significantly more, or less than the estimates provided by equation (2).

The API only recommends the use of these storage loss equations for cases in which the stored petroleum liquids exhibit vapor pressures in the same range as gasolines. However, in the absence of any correlation developed specifically for naphthas, kerosenes, and fuel oils it is recommended that these storage loss equations also be used for the storage of these heavier fuels.

The method most commonly used to control emissions from fixed roof tanks is a vapor recovery system which collects emissions from the storage vessels and converts them to liquid product.

To recover vapor, one or a combination of four methods may be used: vapor/liquid absorption, vapor compression, vapor cooling, and vapor/solid adsorption. Overall control efficiencies of vapor recovery systems vary from 90 to 95 percent, depending on the method used, the design of the unit, the composition of vapors recovered, and the mechanical condition of the system.

Emissions from fixed roof tanks can also be controlled by the addition of an internal floating cover or covered floating roof to the existing fixed roof tank. API reports that this can result in an average loss reduction of 90 percent of the total evaporation loss sustained from a fixed roof tank.[7]

Evaporative emissions can be minimized by reducing tank heat input with water sprays, mechanical cooling, underground storage, tank insulation, and optimum scheduling of tank turnovers.

Floating Roof Tanks[1,5]

Floating roof standing storage losses can be estimated from:

$$L_S = 9.21\times10^{-3} \; M \left[\frac{P}{14.7-P}\right]^{0.7} D^{1.5} \; V_w^{0.7} \; K_t \; K_s \; K_p \; K_c \qquad (3)$$

where: L_S = Floating roof standing storage loss (lb/day).
M = Molecular weight of vapor in storage tank (lb/lb mole); see Table 4.3-3.
P = True vapor pressure at bulk liquid conditions (psia); see Figures 4.3-8, 4.3-9, or Table 4.3-3.
D = Tank diameter (ft); see note (1).
V_w = Average wind velocity (mi/hr); see note (2).
K_t = Tank type factor (dimensionless); see Table 4.3-2.
K_s = Seal factor (dimensionless); see Table 4.3-2.
K_p = Paint factor (dimensionless); see Table 4.3-2.
K_c = Crude oil factor (dimensionless); see note (3).

Note: (1) For $D \geq 150$, use $D\sqrt{150}$ instead of $D^{1.5}$.

(2) API correlation was derived for minimum wind velocity of 4 mph. If $V_w \leq 4$ mph use $V_w = 4$mph.

(3) $K_c = (0.84)$ for crude oil, $K_c = (1.0)$ for all other liquids.

API reports that standing storage losses from gasoline and crude oil storage calculated from equation (3) will not deviate from the actual losses by more than ±25 percent for tanks in good condition under normal operation. However, losses may exceed the calculated amount for seals in poor condition. Although the API only recommends the use of these correlations for petroleum liquids exhibiting vapor pressures in the range of gasoline and crude oils, in the absence of better correlations, these correlations are also recommended with caution for use with heavier naphthas, kerosenes, and fuel oils.

API has developed a correlation based on laboratory data for calculating floating roof withdrawal loss for gasoline storage.[6] Floating roof withdrawal loss for gasoline can be estimated from:

$$L_{WD} = \frac{22.4 \ d \ C_F}{D} \tag{4}$$

where: L_{WD} = Floating roof gasoline withdrawal loss (lb/10^3 gal throughput).

d = Density of stored liquid at bulk liquid conditions (lb/gal); see Table 4.3-3.

C_F = Tank construction factor (dimensionless); see note.

D = Tank diameter (ft).

Note: $C_F = (0.02)$ for steel tanks, $C_F = (1.0)$ for gunite lined tanks.

Equation (4) was derived from gasoline data and its applicability to other stored liquids is uncertain. No estimate of accuracy of equation (4) has been given.

API has not presented any correlations that specifically pertain to internal floating covers or covered floating roofs. Currently, API recommends the use of equations (3) and (4) with a wind speed of 4 mph for calculating the losses from internal floating covers and covered floating roofs.

Evaporative emissions from floating roof tanks can be minimized by reducing tank heat input.

Variable Vapor Space Systems[1,4]

Variable vapor space system filling losses can be estimated from:

$$L_V = (2.40 \times 10^{-2}) \frac{M \quad P}{V_1} \left[(V_1) - (0.25 \quad V_2 \quad N) \right] \qquad (5)$$

where: L_V = Variable vapor space filling loss (lb/10^3 gal throughput).

M = Molecular weight of vapor in storage tank (lb/lb mole); see Table 4.3-3.

P = True vapor pressure at bulk liquid conditions (psia); see Figures 4.3-8, 4.3-9, or Table 4.3-3.

V_1 = Volume of liquid pumped into system: throughput (bbl)

V_2 = Volume expansion capacity of system (bbl); see note (1)

N = Number of transfers into system (dimensionless); see note (2).

Note: (1) V is the volume expansion capacity of the variable vapor space achieved by roof-lifting or diaphragm-flexing.

(2) N is the number of transfers into the system during the time period that corresponds to a throughput of V_1.

The accuracy of equation (5) is not documented, however, API reports that special tank operating conditions may result in actual losses which are significantly different from the estimates provided by equation (5). It should also be noted that although not developed for use with heavier petroleum liquids such as kerosenes and fuel oils, equation (5) is recommended for use with heavier petroleum liquids in the absence of better data.

Evaporative emissions from variable vapor space tanks are negligible and can be minimized by optimum scheduling of tank turnovers and by reducing tank heat input. Vapor recovery systems can be used with variable vapor space systems to collect and recover filling losses.

Vapor recovery systems capture hydrocarbon vapors displaced during filling operations and recover the hydrocarbon vapors by the use of refrigeration, absorption, adsorption, and/or compression. Control efficiencies range from 90 percent to 98 percent depending on the nature of the vapors and the applicable air quality regulations in force.

Pressure Tanks

Pressure tanks incur vapor losses when excessive internal pressures result in relief valve venting. In some pressure tanks vapor venting is a design characteristic and the vented vapors must be routed to a vapor recovery system. However, for most pressure tanks vapor venting is not a normal occurrence and the tanks can be considered closed systems. Fugitive losses are also associated with pressure tanks and their equipment, but with proper system maintenance they are insignificant. Correlations do not exist for estimating vapor losses from pressure tanks.

Emission Factors

Equations (1) through (5) can be used to estimate evaporative losses, provided the respective parameters are known. For those cases where such parameters are unknown, Table 4.3-4 provides emission factors for the typical systems and conditions. It should be emphasized that these emission factors are rough estimates at best for storage of liquids other than gasoline and crude oil, and for storage conditions other than the ones they are based upon. In areas where storage sources contribute a substantial portion of the total evaporative emissions or where they are major factor affecting the air quality, it is advisable to obtain the necessary parameters and to calculate emission estimates using equations (1) through (5).

Sample Calculation

Breathing losses from a fixed roof storage tank would be calculated as follows, using equation (1).

Design basis

tank capacity - 100,000 bbl
tank diameter - 125 ft.
tank height - 46 ft.
average diurnal temperature change - 15°F
gasoline RVP - 9 psia
gasoline temperature - 70°F
specular aluminum painted tank
roof slope is 0.1 ft/ft

Fixed roof tank breathing loss equation

$$L_B = 2.21 \times 10^{-4} M \left[\frac{P}{14.7-P}\right]^{0.68} D^{1.73} H^{0.51} \Delta T^{0.50} F_p C K_c$$

where

M = Molecular wt of gasoline vapors (see Table 4.3-3)≈66.

P = true vapor of gasoline (see Figure 4.3-8)=5.6 psia

D = tank diameter = 125 ft.

ΔT = average diurnal temperature change = 15°F

F_p = paint factor (see Table 4.3-1) = 1.20

C = tank diameter adjustment factor (see Figure 4.3-10)=1.0.

K_c = crude oil factor (see note for equation (1)=1.0.

H = average vapor space height. For a tank which is filled completely and emptied, the average liquid level is ½ the tank rim height, or 23 ft. The effective cone height is 1/3 of the cone height. The roof slope is 0.1 ft/ft and the tank radius is 62.5 ft. Effective cone height = (62.5 ft) (0.1 ft/ft) (1/3)=2.08 ft.

H = average vapor space height = 23 ft + 2 ft = 25 ft.

Therefore:

$$L_B = 2.21 \times 10^{-4} (66) \left[\frac{5.6}{14.7-5.6}\right]^{0.68} (125)^{1.73} (25)^{0.51} (15)^{0.50} (1.2)(1.0)(1.0)$$

$$L_B = 1068 \text{ lbs/day}$$

TABLE 4.3-1

PAINT FACTORS FOR FIXED ROOF TANKS[3]

Tank Color		Paint Factors (F_p)	
		Paint Condition	
Roof	Shell	Good	Poor
White	White	1.00	1.15
Aluminum (specular)	White	1.04	1.18
White	Aluminum (specular)	1.16	1.24
Aluminum (specular)	Aluminum (specular)	1.20	1.29
White	Aluminum (diffuse)	1.30	1.38
Aluminum (diffuse)	Aluminum (diffuse)	1.39	1.46
White	Gray	1.30	1.38
Light gray	Light gray	1.33	1.44*
Medium gray	Medium gray	1.46	1.58*

*Estimated from the ratios of the seven preceding paint factors.

TABLE 4.3-2

TANK, TYPE, SEAL, AND PAINT FACTORS FOR FLOATING ROOF TANKS[3]

Tank Type	K_t
Welded tank with pan or pontoon roof, single or double seal.	0.045
Riveted tank with pontoon roof, double seal.	0.11
Riveted tank with pontoon roof, single seal.	0.13
Riveted tank with pan roof, double seal.	0.13
Riveted tank with pan roof, single seal.	0.14

Seal Type	K_s
Tight fitting (typical of modern metallic and non-metallic seals)	1.00
Loose fitting (typical of seals built prior to 1942).	1.33

Paint Color of Shell and Roof	K_P
Light gray or aluminum	1.0
White	0.9

TABLE 4.3-3

PHYSICAL PROPERTIES OF HYDROCARBONS [1, 8]

Hydrocarbon	Vapor Molecular Weight @ 60°F	Product Density (d) lb/gal @ 60°F	Condensed Vapor Density (w) lb/gal @ 60°F	Vapor Pressure in psia at: 40°	50°F	60°F	70°F	80°F	90°F	100°F
Fuels										
Gasoline RVP 13	62	5.6	4.9	4.7	5.7	6.9	8.3	9.9	11.7	13.8
Gasoline RVP 10	66	5.6	5.1	3.4	4.2	5.2	6.2	7.4	8.8	10.5
Gasoline RVP 7	68	5.6	5.2	2.3	2.9	3.5	4.3	5.2	6.2	7.4
Crude Oil RVP 5	50	7.1	4.5	1.8	2.3	2.8	3.4	4.0	4.8	5.7
Jet Naphtha (JP-4)	80	6.4	5.4	0.8	1.0	1.3	1.6	1.9	2.4	2.7
Jet Kerosene	130	7.0	6.1	0.0041	0.0060	0.0085	0.011	0.015	0.021	0.029
Distillate Fuel No. 2	130	7.1	6.1	0.0031	0.0045	0.0074	0.0090	0.012	0.016	0.022
Residual Oil No. 6	190	7.9	6.4	0.00002	0.00003	0.00004	0.00006	0.00009	0.00013	0.00019
Petrochemicals										
Acetone	58	6.6	6.6	1.7	2.2	2.9	3.7	4.7	5.9	7.3
Acrylonitrile	53	6.8	6.8	0.8	1.0	1.4	1.8	2.4	3.1	4.0
Benzene	78	7.4	7.4	0.6	0.9	1.2	1.5	2.0	2.6	3.3
Carbon Disulfide	76	10.6	10.6	3.0	3.9	4.8	6.0	7.4	9.2	11.2
Carbon tetrachloride	154	13.4	13.4	0.8	1.1	1.4	1.8	2.3	3.0	3.8
Chloroform	119	12.5	12.5	1.5	1.9	2.5	3.2	4.1	5.2	6.3
Cyclohexane	84	6.5	6.5	0.7	0.9	1.2	1.6	2.1	2.6	3.2
1, 2 - Dichlorethane	99	10.5	10.5	0.6	0.8	1.0	1.4	1.7	2.2	2.8
Ethylacetate	88	7.6	7.6	0.6	0.8	1.1	1.5	1.9	2.5	3.2
Ethyl alcohol	46	6.6	6.6	0.2	0.4	0.6	0.9	1.2	1.7	2.3
Isopropyl alcohol	60	6.6	6.6	0.2	0.3	0.5	0.7	0.9	1.3	1.8
Methyl alcohol	32	6.6	6.6	0.7	1.0	1.4	2.0	2.6	3.5	4.5
Methylene chloride	85	11.1	11.1	3.1	4.3	5.4	6.8	8.7	10.3	13.3
Methyl-ethyl-ketone	72	6.7	6.7	0.7	0.9	1.2	1.5	2.1	2.7	3.3
Methyl-methacrylate	100	7.9	7.9	0.1	0.2	0.3	0.5	0.8	1.1	1.4
1, 1, 1 - Trichloroethane	133	11.2	11.2	0.9	1.2	1.6	2.0	2.6	3.3	4.2
Trichloroethylene	131	12.3	12.3	0.5	0.7	0.9	1.2	1.5	2.0	2.6
Toluene	92	7.3	7.3	0.2	0.2	0.3	0.4	0.6	0.8	1.0
Vinylacetate	86	7.8	7.8	0.7	1.0	1.3	1.7	2.3	3.1	4.0

TABLE 4.3-4

EVAPORATIVE EMISSION FACTORS FOR STORAGE TANKS[1,2,3,4,5]

Product Stored	FIXED ROOF TANKS						FLOATING ROOF TANKS						VARIABLE VAPOR SPACE TANKS 10,500 bbl	
	Breathing Loss				Working Loss		Standing Storage Loss				Withdrawal Loss		Filling Loss	
	"New tank" Conditions		"Old tank" Conditions				"New Tank" Conditions		"Old Tank" Conditions					
	lb/day-10^3 gal	Kg/day-10^3 liter	lb/day-10^3 gal	Kg/day-10^3 liter	lb/10^3 gal throughput	Kg/10^3 liter throughput	lb/day-10^3 gal	Kg/day-10^3 liter	lb/day-10^3 gal	Kg/day-10^3 liter	lb/10^3 gal throughput	Kg/10^3 liter throughput	lb/10^3 gal throughput	Kg/10^3 liter throughput
Fuels - 67,000 bbl tanks														
1. Gasoline RVP 13	0.30	0.036	0.34	0.041	10.0	1.2	0.044	0.0052	0.10	0.012	0.023	0.0028	9.6	1.2
2. Gasoline RVP 10	0.23	0.028	0.26	0.031	8.2	0.99	0.033	0.0040	0.078	0.0094	0.023	0.0028	7.7	0.93
3. Gasoline RVP 7	0.16	0.019	0.18	0.022	5.7	0.68	0.023	0.0028	0.055	0.0066	0.023	0.0028	5.4	0.65
4. Crude oil RVP 5	0.064	0.0077	0.073	0.0088	2.8	0.34	0.012	0.0014	0.028	0.0034			Not used	Not used
5. Jet naphtha (JP-4)	0.086	0.010	0.098	0.011	2.5	0.30	0.012	0.0014	0.028	0.0034			2.3	0.28
6. Jet kerosene	0.0041	0.00052	0.0049	0.00059	0.027	0.0032	0.00054	0.000065	0.0013	0.00016			0.025	0.0030
7. Distillate fuel no. 2	0.0039	0.00047	0.0044	0.00053	0.023	0.0028	0.00049	0.000058	0.0011	0.00014			0.022	0.0026
8. Residual oil no. 6	0.00016	0.000019	0.00018	0.000022	0.00018	0.000022	0.000018	0.0000022	0.000043	0.0000052			0.00017	0.000020
Fuels - 250,000 bbl tanks														
9. Gasoline RVP 13	0.22	0.026	0.25	0.030	10.0	1.2	0.025	0.0030	0.057	0.0068	0.013	0.0015	Not used	Not used
10. Gasoline RVP 10	0.17	0.020	0.19	0.023	8.2	0.99	0.019	0.0023	0.044	0.0053	0.013	0.0015	Not used	Not used
11. Gasoline RVP 7	0.12	0.014	0.13	0.016	5.7	0.68	0.013	0.0016	0.031	0.0037	0.013	0.0015	Not used	Not used
12. Crude oil RVP 5	0.046	0.0055	0.052	0.0062	2.8	0.34	0.0077	0.0092	0.018	0.0022			Not used	Not used
13. Jet naphtha (JP-4)	0.062	0.0074	0.071	0.0085	2.5	0.30	0.0068	0.00082	0.016	0.0019			Not used	Not used
14. Jet kerosine	0.0031	0.0037	0.0035	0.00042	0.027	0.0032	0.00031	0.000037	0.00074	0.000089			Not used	Not used
15. Distillate fuel no. 2	0.0028	0.00034	0.0032	0.00038	0.023	0.0028	0.00028	0.000034	0.00068	0.000082			Not used	Not used
16. Residual fuel no. 6	0.00012	0.000014	0.00014	0.000017	0.00018	0.000022	0.000010	0.0000012	0.000024	0.0000029			Not used	Not used
Petrochemicals - 67,000 bbl tanks														
17. Acetone	0.12	0.014	0.14	0.016	4.0	0.48	0.017	0.0020	0.039	0.0047			3.8	0.45
18. Acrylonitrile	0.060	0.0072	0.068	0.0082	1.8	0.21	0.0084	0.0010	0.020	0.0024			1.7	0.20
19. Benzene	0.079	0.0094	0.090	0.011	2.2	0.27	0.011	0.0013	0.026	0.0031			2.1	0.25
20. Carbon disulfide	0.24	0.029	0.28	0.033	8.8	1.1	0.035	0.0042	0.083	0.0099			8.2	0.98
21. Carbon tetrachloride	0.17	0.021	0.20	0.024	5.2	0.62	0.024	0.0029	0.056	0.0069			4.8	0.58
22. Chloroform	0.21	0.025	0.24	0.029	7.1	0.86	0.010	0.0036	0.071	0.0085			6.7	0.80
23. Cyclohexane	0.085	0.010	0.096	0.012	2.4	0.29	0.012	0.0014	0.028	0.0034			2.3	0.27
24. 1,2-Dichlorethane	0.087	0.010	0.10	0.012	2.4	0.28	0.012	0.0014	0.029	0.0034			2.2	0.27
25. Ethyl acetate	0.083	0.010	0.095	0.011	2.3	0.28	0.012	0.0014	0.027	0.0033			2.2	0.26
26. Ethyl alcohol	0.028	0.0034	0.032	0.0038	0.66	0.079	0.0039	0.00046	0.0091	0.0011			0.62	0.074
27. Isopropyl alcohol	0.031	0.0038	0.036	0.0043	0.72	0.086	0.0043	0.00052	0.010	0.0012			0.68	0.082
28. Methyl alcohol	0.036	0.0044	0.042	0.0050	1.1	0.13	0.0051	0.00061	0.012	0.0014			1.0	0.12
29. Methylene chloride	0.31	0.037	0.35	0.042	11.0	1.3	0.044	0.0053	0.10	0.012			10.0	1.2
30. Methyl-ethyl-ketone	0.073	0.0087	0.083	0.0099	2.1	0.25	0.010	0.0012	0.024	0.0029			1.9	0.23
31. Methyl methacrylate	0.038	0.0046	0.043	0.0052	0.72	0.086	0.0051	0.00061	0.012	0.0015			0.68	0.082
32. 1,1,1-Trichloroethane	0.17	0.020	0.19	0.023	5.1	0.61	0.023	0.0028	0.055	0.0066			4.8	0.58
33. Trichloroethylene	0.11	0.013	0.12	0.014	2.8	0.34	0.015	0.0018	0.035	0.0042			2.6	0.31
34. Toluene	0.035	0.0042	0.040	0.0048	0.66	0.079	0.0048	0.00058	0.011	0.0014			0.62	0.074
35. Vinyl acetate	0.092	0.011	0.10	0.013	2.7	0.32	0.013	0.0016	0.030	0.0037			2.5	0.30

Emission factors based on the following parameters:

Ambient conditions:
Storage temperature: 60°F (15.6°C).
Daily ambient temperature change: 15°F (8.3°C).
Wind velocity: 10 mi/hr (4.5 m/sec).

Typical fixed roof tanks:
Outage: 50 percent of tank height.
Turnovers per year (N): 30 for crude; 13 for all other liquids.
Paint factor (F_p): New tank-white paint=1.00;
Old tank-white/aluminum paint=1.14.

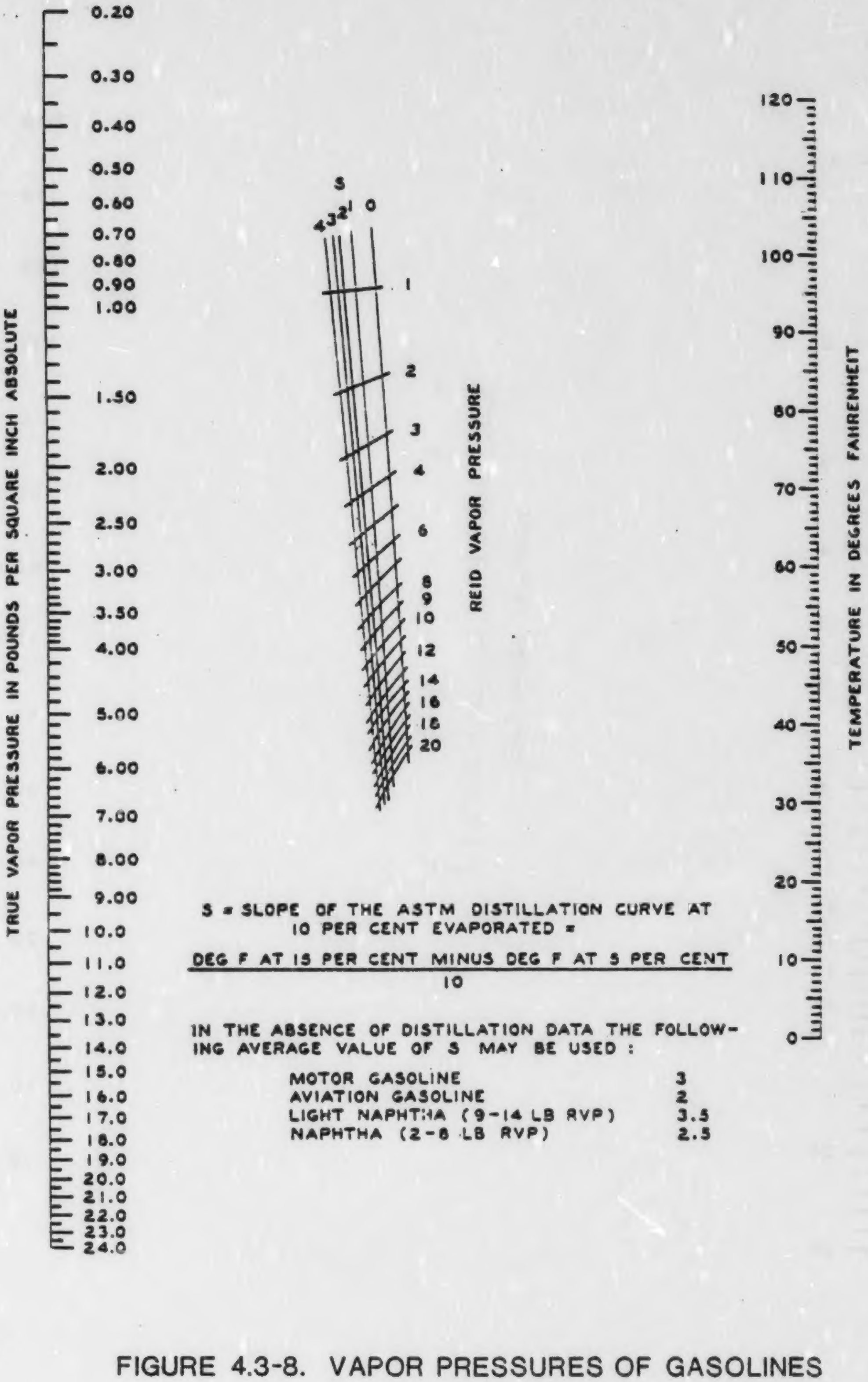
For 67,000 bbl tankage (10.7 x 10^6 liter)
Height: 48 ft (14.6m)
Diameter: 110 ft (33.5m)

For 250,000 bbl tankage (39.7 x 10^6 liter)
Height: 44 ft (13.4m)
Diameter: 200 ft (60.8m)

Emission factors based on the following parameters:

Typical floating roof tanks:
Paint factor (K_p): New tank-white paint-0.090;
Old tank-white/aluminum paint-0.95.
Seal factor (K_s): New tank-modern seals-1.00;
Old tank-50 percent old seals=1.14.
Tank type factor (Kt): New tank-welded-0.045;
Old tank-50 percent riveted=0.088.

Typical variable space tank:
Diameter: 50 ft (15.2m)
Height: 30 ft (9.1m)
Capacity: 10,500 bbl (1.67 x 10^6 liter)
Turnovers per year (N): 6
Volume expansion capacity: one fourth of liquid capacity = 2625 bbl (0.42 x 10^6 ℓ).



$$S = \text{SLOPE OF THE ASTM DISTILLATION CURVE AT 10 PER CENT EVAPORATED} = \frac{\text{DEG F AT 15 PER CENT MINUS DEG F AT 5 PER CENT}}{10}$$

IN THE ABSENCE OF DISTILLATION DATA THE FOLLOWING AVERAGE VALUE OF S MAY BE USED :

MOTOR GASOLINE	3
AVIATION GASOLINE	2
LIGHT NAPHTHA (9-14 LB RVP)	3.5
NAPHTHA (2-8 LB RVP)	2.5

FIGURE 4.3-8. VAPOR PRESSURES OF GASOLINES AND FINISHED PETROLEUM PRODUCTS

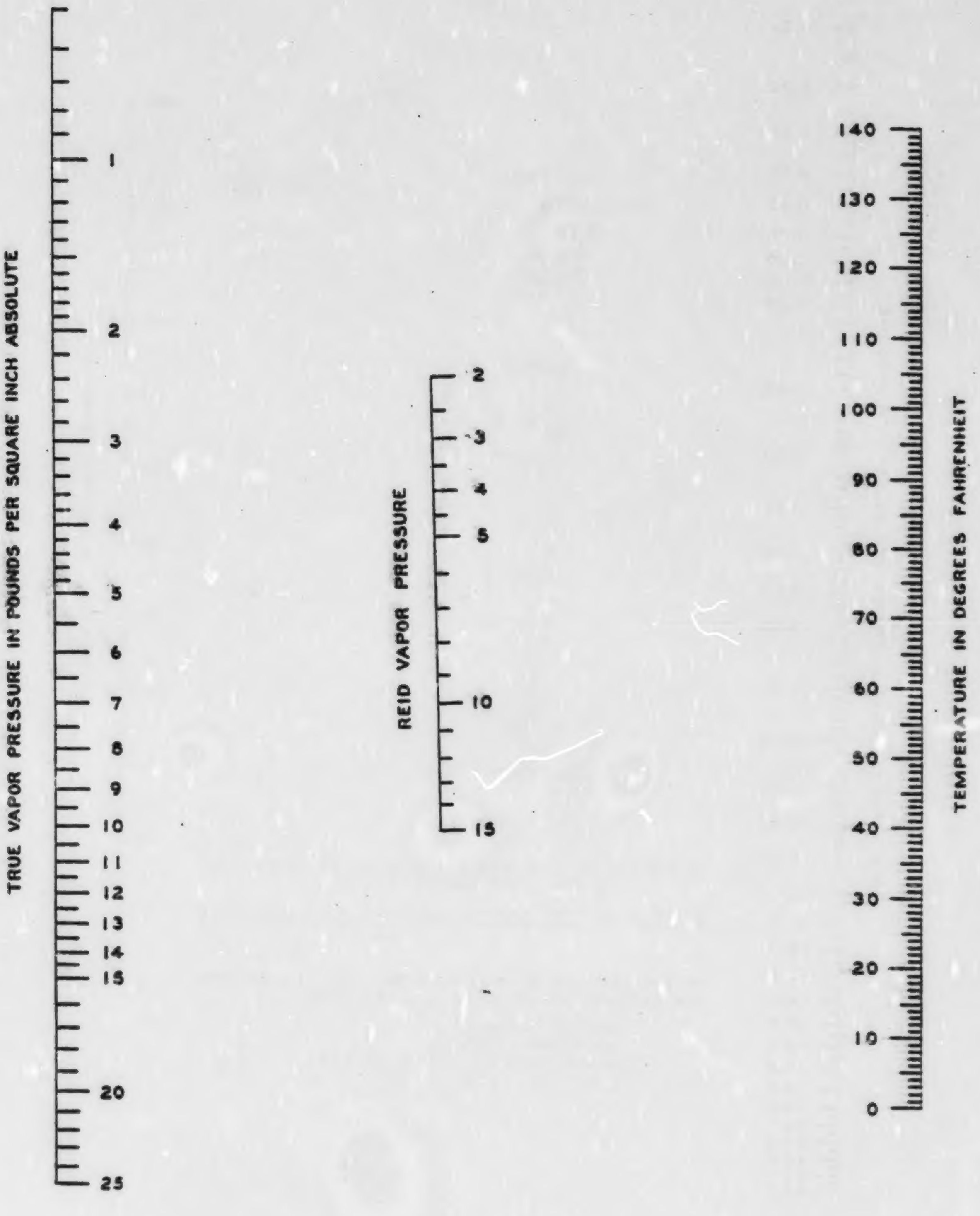


FIGURE 4.3-9. VAPOR PRESSURES OF CRUDE OIL.

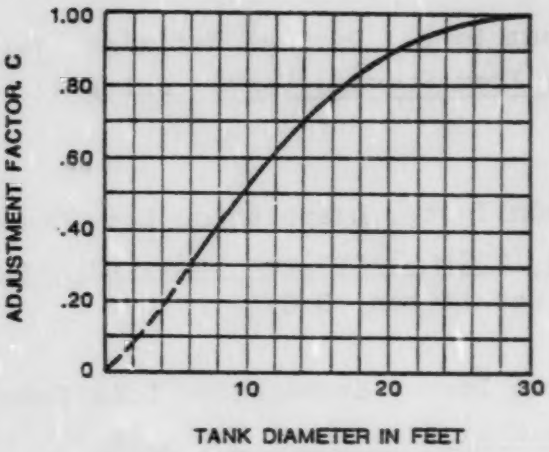


FIGURE 4.3-10. ADJUSTMENT FACTOR (C) FOR SMALL DIAMETER TANKS

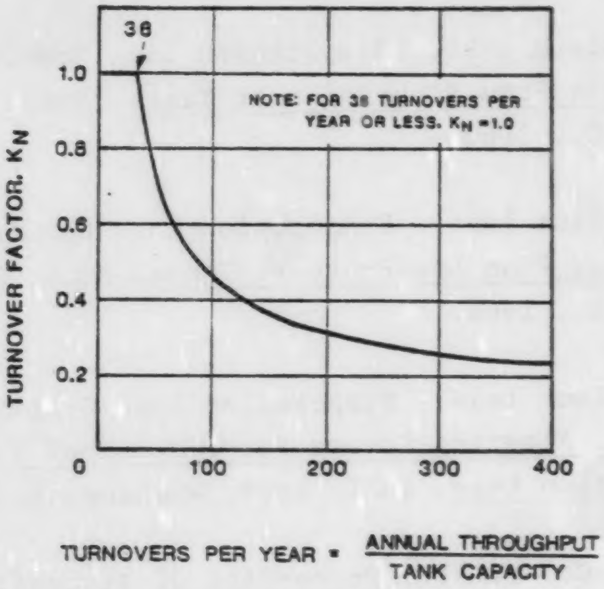


FIGURE 4.3-11. TURNOVER FACTOR (K_N) FOR FIXED ROOF TANKS

REFERENCES

SECTION 4.3

1. American Petroleum Inst., Div. of Refining, Petrochemical Evaporation Loss From Storage Tanks, API Bull. 2523, N.Y., 1969.

2. American Petroleum Inst., Evaporation Loss Committee, Evaporation Loss In The Petroleum Industry, Causes and Control, API Bull. 2513, Washington, D.C. 1959.

3. American Petroleum Inst., Evaporation Loss Committee, Evaporation Loss From Fixed-Roof Tanks, Bull. 2518, Washington, D.C., 1962.

4. American Petroleum Inst., Evaporation Loss Committee, Use Of Variable Vapor-Space Systems To Reduce Evaporation Loss, loss, Bull. 2520, N.Y., N.Y., 1964.

5. American Petroleum Inst., Evaporation Loss Committee, Evaporation Loss From Floating-roof Tanks, Bull. 2517, Washington, D.C., 1962.

6. American Petroleum Inst., Evaporation Loss Committee, Evaporation Loss From Low-Pressure Tanks, Bull. 2516, Washington, D.C., 1962.

7. American Petroleum Inst., Evaporation Loss Committee, Use Of Internal Floating Covers For Fixed-Roof Tanks To Reduce Evaporation Loss, Bull. 2519, Washington, D.C., 1962.

8. Barnett, Henry C., et al., Properties Of Aircraft Fuels, NACATN 3276, Cleveland, Ohio, Lewis Flight Propulsion Lab., August, 1956.

REFERENCES
SECTION 4.3
Continued

9. Bridgeman, Oscar C. and Elizabeth W. Aldrich, Some Phases Of The Problem Of Evaluating Evaporation Losses From Petroleum Products By Means Of Vapor Volume Measurements. Report 128855R, Bartlesville, Oklahoma, Phillips Petroleum Company, undated.

10. Environmental Protection Agency, Compilation Of Air Pollutant Emission Factors, 2nd ed. with supplements, AP-42, Research Triangle Park, N.C., 1973.

ATTACHMENT B
TRANSPORTATION AND LOADING LOSSES

Preceding page blank

4.4 TRANSPORTATION AND MARKETING OF PETROLEUM LIQUIDS

4.4.1 Process Description

As Figure 4.4-1 indicates, the transportation and marketing of petroleum liquids involves many distinct operations, each of which represents a potential source of hydrocarbon evaporation loss. Crude oil is transported from production operations to the refinery via tankers, barges, tank cars, tank trucks, and pipelines. In the same manner refined petroleum products are conveyed to fuel marketing terminals and petrochemical industries by tankers, barges, tank cars, tank trucks, and pipelines. From the fuel marketing terminals the fuels are delivered via tank trucks to service stations, commercial accounts, and local bulk storage plants. The final destination for gasoline is normally a motor vehicle gasoline tank. A similar distribution path may also be developed for fuel oils and other petroleum products.

4.4.2 Emissions and Controls

Evaporative hydrocarbon emissions from the transportation and marketing of petroleum liquids may be separated into four categories, depending on the storage equipment and mode of transportation used:

1. Large storage tanks: Breathing, working, and standing storage losses,
2. Marine vessels, tank cars, and tank trucks: Loading and transit losses,
3. Service stations: Bulk fuel drop losses and underground tank breathing losses, and,
4. Motor vehicle tanks: Refueling losses.

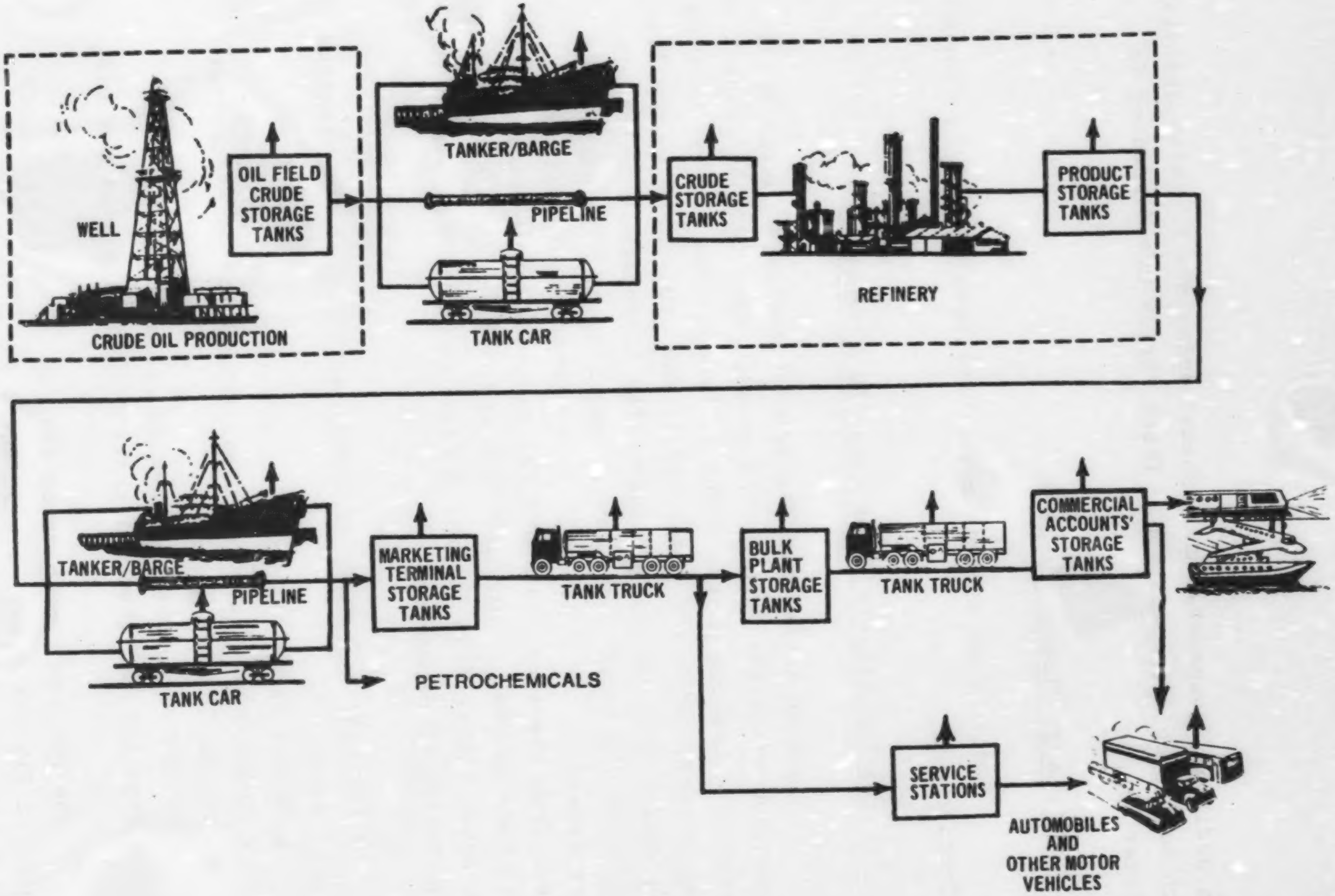

WELL
CRUDE OIL PRODUCTION
OIL FIELD CRUDE STORAGE TANKS
TANKER/BARGE
PIPELINE
TANK CAR
CRUDE STORAGE TANKS
REFINERY
PRODUCT STORAGE TANKS
TANKER/BARGE
PIPELINE
TANK CAR
PETROCHEMICALS
MARKETING TERMINAL STORAGE TANKS
TANK TRUCK
BULK PLANT STORAGE TANKS
TANK TRUCK
COMMERCIAL ACCOUNTS' STORAGE TANKS
SERVICE STATIONS
AUTOMOBILES AND OTHER MOTOR VEHICLES

Figure 4.4-1. Flowsheet of petroleum production, refining, and distribution systems. (Sources of organic evaporative emissions are indicated by vertical arrows).

(In addition, evaporates and exhaust emissions are also associated with motor vehicle operation. These topics are discussed in Chapter 3).

Large Storage Tanks

Losses from storage tanks have been thoroughly discussed in Section 4.3

Marine Vessels, Tank Cars, Tank Trucks

Loading losses are the primary source of evaporative hydrocarbon emissions from marine vessel, tank car, and tank truck operations. Loading losses occur as hydrocarbon vapors residing in empty cargo tanks are displaced to the atmosphere by the liquid being loaded into the cargo tanks. The hydrocarbon vapors displaced from the cargo tanks are a composite of (1) hydrocarbon vapors formed in the empty tank by evaporation of residual product from previous hauls and (2) hydrocarbon vapors generated in the tank as the new product is being loaded. The quantity of hydrocarbon losses from loading operations is, therefore, a function of the following parameters:

- Physical and chemical characteristics of the previous cargo,
- Method of unloading the previous cargo,
- Operations during the transport of the empty carrier to the loading terminal,
- Method of loading the new cargo, and
- Physical and chemical characteristics of the new cargo.

The two basic methods of loading cargo carriers are presented in Figures 4.4-2, 4.4-3, and 4.4-4. In the splash loading method, the fill pipe dispensing the cargo is only

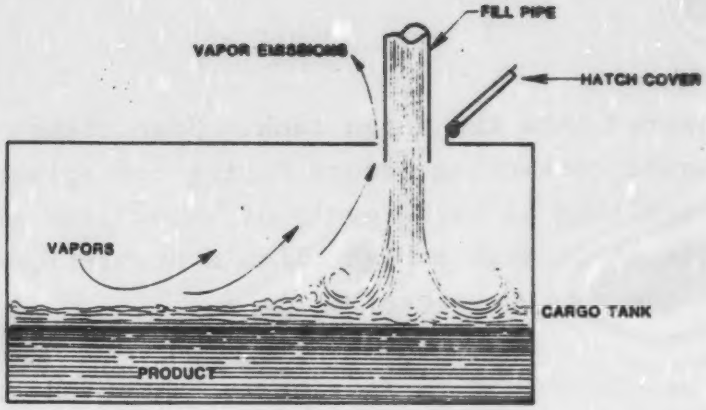

FILL PIPE
VAPOR EMISSIONS
HATCH COVER
VAPORS
CARGO TANK
PRODUCT

FIGURE 4.4-2 SPLASH LOADING METHOD

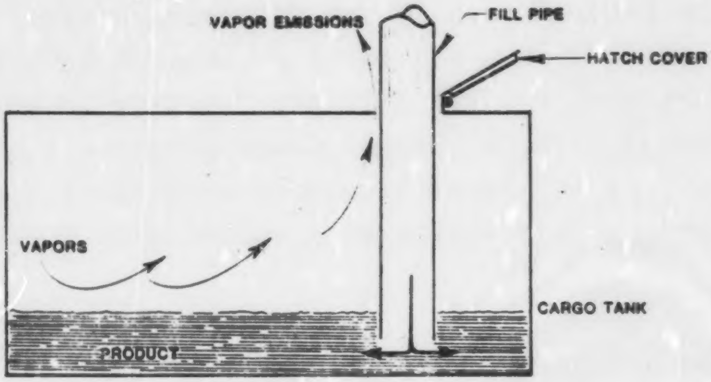

VAPOR EMISSIONS
FILL PIPE
HATCH COVER
VAPORS
CARGO TANK
PRODUCT

FIGURE 4.4-3 SUBMERGED FILL PIPE

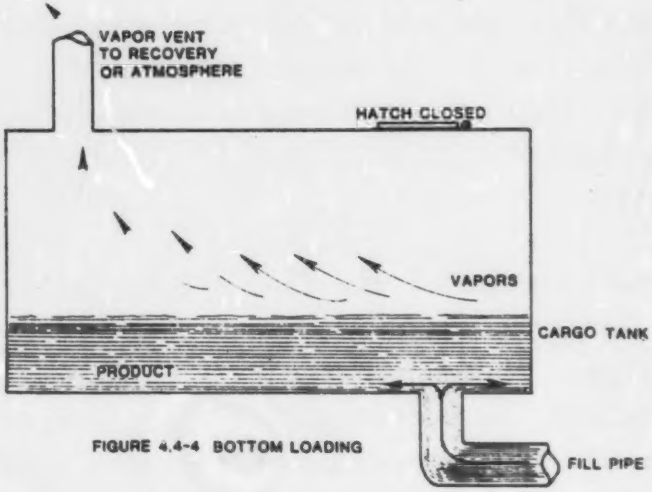

VAPOR VENT
TO RECOVERY
OR ATMOSPHERE
HATCH CLOSED
VAPORS
CARGO TANK
PRODUCT
FILL PIPE

FIGURE 4.4-4 BOTTOM LOADING

partially lowered into the cargo tank. Significant turbulence and vapor-liquid contacting occurs during the splash loading operation, resulting in high levels of vapor generation and loss. If the turbulence is high enough, liquid droplets will be entrained in the vented vapors.

A second method of loading is submerged loading. The two types of submerged loading are the submerged fill pipe method and the bottom loading method. In the submerged fill pipe method, the fill pipe descends almost to the bottom of the cargo tank. In the bottom loading method, the fill pipe enters the cargo tank from the bottom. During the major portion of both forms of submerged loading methods, the fill pipe opening is positioned below the liquid level. The submerged loading method significantly reduces liquid turbulence and vapor-liquid contacting, thereby resulting in much lower hydrocarbon losses than encountered during splash loading methods.

The history of a cargo carrier is just as important a factor in loading losses as the method of loading. Hydrocarbon emissions are generally lowest from a clean cargo carrier whose cargo tanks are free from vapors prior to loading. Clean cargo tanks normally result from either carrying a non-volatile liquid such as heavy fuel oils in the previous haul, or from cleaning or venting the empty cargo tank prior to loading operations. A fully ballasted tanker compartment will also be relatively free from hydrocarbon vapors.

In normal dedicated service, a cargo carrier is dedicated to the transport of only one product and does not clean or vent its tanks between trips. An empty cargo tank in normal dedicated service will retain a low but significant concentration of vapors which were generated by evaporation of residual product on the tank surfaces. These residual vapors are expelled along with newly generated vapors during the subsequent loading operation.

A third type of cargo carrier is one in dedicated balance service. Cargo carriers in dedicated balance service pick up vapors displaced during unloading operations and transport these vapors in the empty cargo tanks back to the loading terminal. Figure 4.4-5 shows a tank truck in dedicated vapor balance service unloading gasoline to an underground service station tank and filling up with displaced gasoline vapors to be returned to the truck loading terminal. The vapors in an empty cargo carrier in dedicated balance service are normally saturated with hydrocarbons.

Emissions from loading hydrocarbon liquids can be estimated (within 30 percent) using the following expression:

$$L_L = 12.46 \frac{SPM}{T} \qquad (1)$$

where:

L_L = loading loss, lb/10^3 gal of liquid loaded.
M = molecular weight of vapors, lb/lb-mole (see Table 4.3-3).
P = true vapor pressure of liquid loaded, psia (see Figures 4.3-8 and 4.3-9, and Table 4.3-3).
T = bulk temperature of liquid loaded, °R.
S = a saturation factor (see Table 4.4-1).

The saturation factor (S) represents the expelled vapor's fractional approach to saturation and accounts for the variations observed in emission rates from the different unloading and loading methods. Table 4.4-1 lists suggested saturation factors (S).

The API has recently developed a separate set of factors for calculating the hydrocarbon emission rate from loading gasoline onto marine tankers and barges. These factors are presented in Table 4.4-2 and should be used instead of equation (1) for gasoline loading operations at marine terminals.

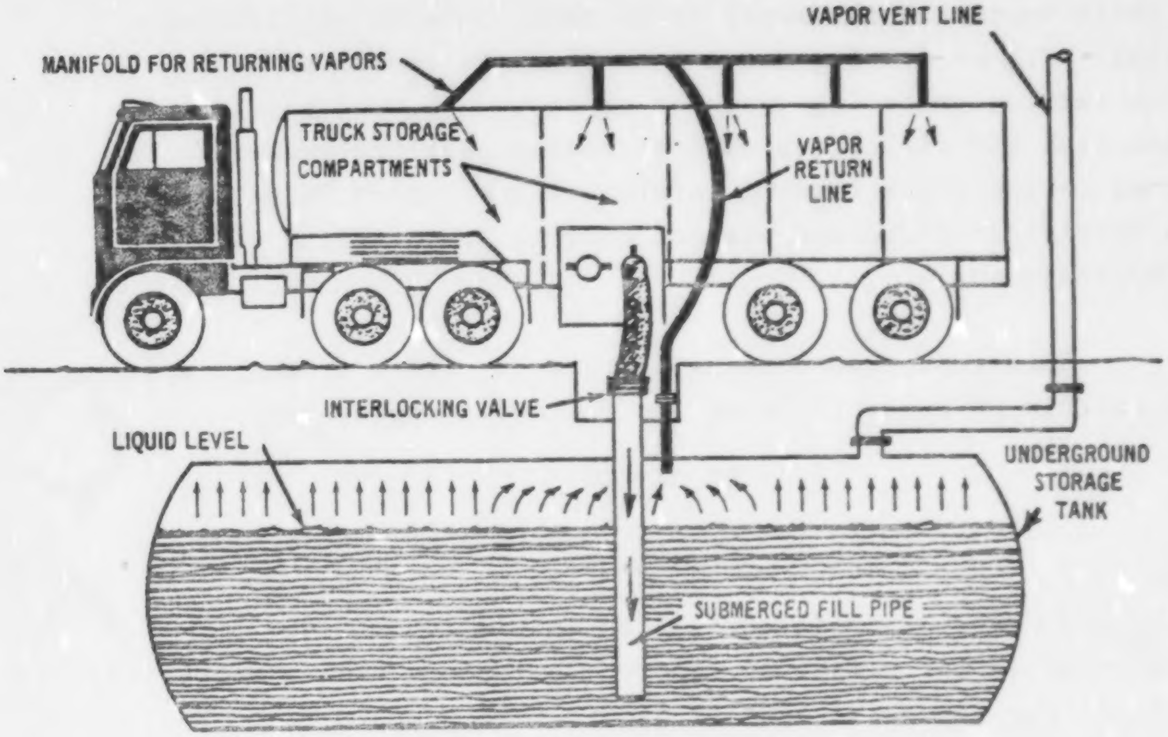

VAPOR VENT LINE
MANIFOLD FOR RETURNING VAPORS
TRUCK STORAGE
COMPARTMENTS
VAPOR
RETURN
LINE
INTERLOCKING VALVE
LIQUID LEVEL
UNDERGROUND
STORAGE
TANK
SUBMERGED FILL PIPE

FIGURE 4.4-5 TANKTRUCK UNLOADING INTO AN UNDERGROUND SERVICE STATION STORAGE TANK. TANKTRUCK IS PRACTICING " VAPOR BALANCE " FORM OF VAPOR CONTROL.

TABLE 4.4-1

S FACTORS FOR CALCULATING LOADING LOSSES[1]

Tank Trucks and Tank Cars	S
submerged loading of a clean cargo tank	0.50
splash loading of a clean cargo tank	1.45
submerged loading - normal dedicated service	0.60
splash loading - normal dedicated service	1.45
submerged loading - dedicated, vapor balance service	1.0
splash loading - dedicated, vapor balance service	1.0
Marine Vessels*	
submerged loading	0.20

---

*To be used for products other than gasoline.
Use factors from Table 4.4-2 for marine loading of gasoline.

An additional emission source associated with marine vessel, tank car, and tank truck operations is transit losses. During the transportation of petroleum liquids small quantities of hydrocarbon vapors are expelled from cargo tanks due to temperature and barometric pressure changes. The most significant transit loss is from tanker and barge operations and can be calculated using equation (2).[1]

$$L_T = 0.1\ PW \qquad (2)$$

where:

L_T = transit loss, lb/week-10^3 gal transported.

P = true vapor pressure of the transported liquid, psia (see Figures 4.3-8 and 4.3-9, and Table 4.3-3).

W = density of the condensed vapors, lb/gal (see Table 4.3-3).

In the absence of specific inputs for equations (1) and (2) typical evaporative hydrocarbon emissions from loading operations are presented in Table 4.4-2. It should be noted that although the crude oil used to calculate the emission values presented in Table 4.4-2 has an RVP of 5, the RVP of crude oils can range over two orders of magnitude. In areas where loading and transportation sources are a major factor affecting the air quality, it is advisable to obtain the necessary parameters and to calculate emission estimates from equations (1) and (2).

Control measures for reducing loading emissions include the application of alternate loading methods producing lower emissions, and the application of vapor recovery equipment. Vapor recovery equipment captures hydrocarbon vapors displaced during loading operations and recovers the hydrocarbon vapors by the use of refrigeration, absorption, adsorption, and/or compression. Figure 4.4-6 demonstrates the recovery of gasoline vapors from tank trucks

TABLE 4.4-2

ORGANIC COMPOUND EVAPORATIVE EMISSION FACTORS FOR UNCONTROLLED PETROLEUM TRANSPORTATION AND MARKETING SOURCES

EMISSION SOURCES	PRODUCT					
	Gasoline	Crude Oil	Jet Naphtha (JP-4)	Jet Kerosene	Distillate Oil No. 2	Residual Oil No. 6
Tank cars/trucks						
submerged loading-normal service						
$lb/10^3$ gal transferred	5	3	1.5	0.02	0.01	0.0001
$Kg/10^3$ liter transferred	0.6	0.4	0.18	0.002	0.001	0.00001
splash loading-normal service						
$lb/10^3$ gal transferred	12	7	4	0.04	0.03	0.0003
$Kg/10^3$ liter transferred	1.4	0.8	0.5	0.005	0.004	0.00004
submerged loading-balance service						
$lb/10^3$ gal transferred	8	5	2.5	*	*	*
$Kg/10^3$ liter transferred	1.0	0.6	0.3			
splash loading-balance service						
$lb/10^3$ gal transferred	8	5	2.5	*	*	*
$Kg/10^3$ liter transferred	1.0	0.6	0.3			
Marine Vessels						
loading-general						
$lb/10^3$ gal transferred		1.0	0.5	0.02	0.005	0.00004
$Kg/10^3$ liter transferred		0.1	0.06	0.001	0.0006	$5x10^{-6}$
loading-clean ships						
$lb/10^3$ gal transferred	1.3					
$Kg/10^3$ liter transferred	0.16					
loading-dirty ships						
$lb/10^3$ gal transferred	2.5					
$Kg/10^3$ liter transferred	0.30					
loading-clean barges						
$lb/10^3$ gal transferred	1.2					
$Kg/10^3$ liter transferred	0.14					
loading-dirty barges						
$lb/10^3$ gal transferred	3.8					
$Kg/10^3$ liter transferred	0.46					
transit						
$lb/week-10^3$ gal transported	3	1	0.7	0.02	0.005	$3x10^{-5}$
$Kg/week-10^3$ liter transported	0.4	0.1	0.08	0.002	0.0006	$4x10^{-6}$

1. Emission factors are calculated for a dispensed fuel temperature of 60°F.
2. The example gasoline has an RVP of 10 psia.
3. The example crude oil has an RVP of 5 psia.

* Not normally used.

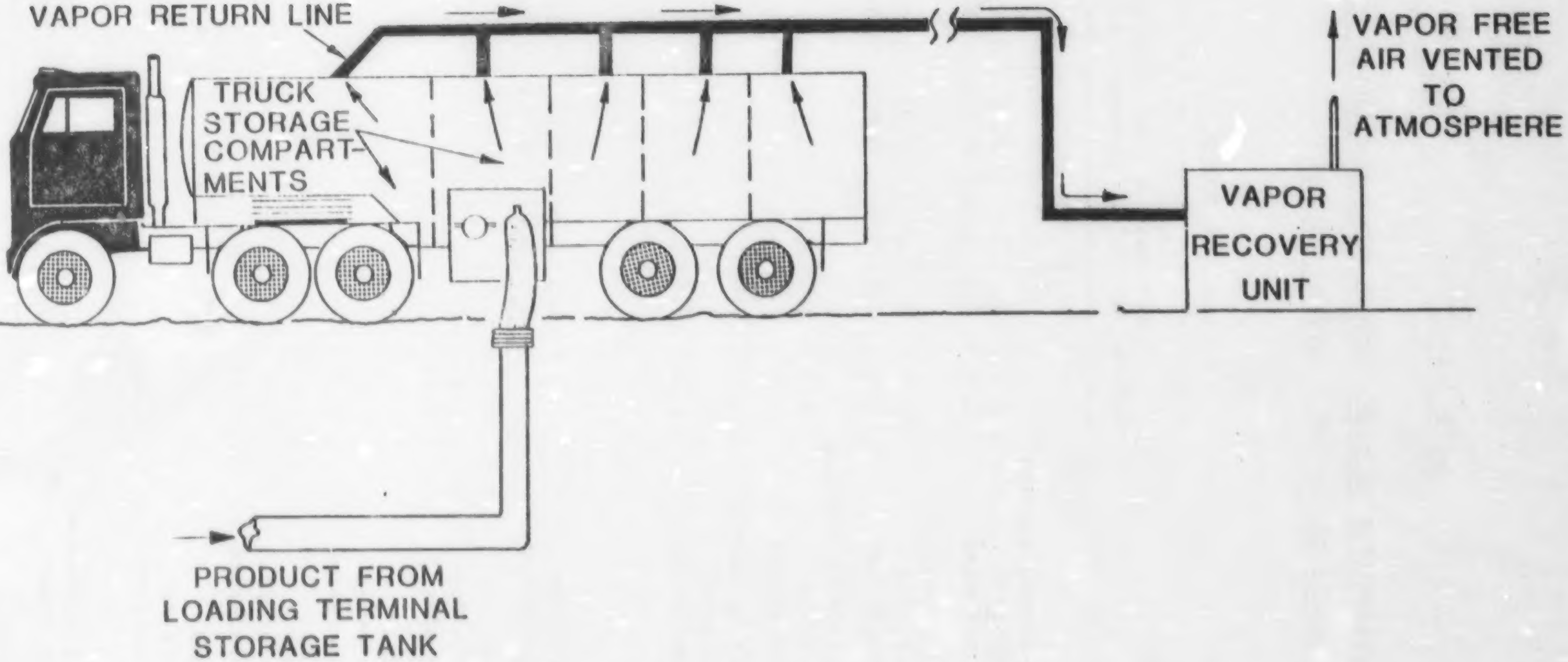

VAPOR RETURN LINE
TRUCK STORAGE COMPARTMENTS
VAPOR FREE AIR VENTED TO ATMOSPHERE
VAPOR RECOVERY UNIT
PRODUCT FROM LOADING TERMINAL STORAGE TANK

FIGURE 4.4-6 TANKTRUCK LOADING WITH VAPOR RECOVERY

during loading operation at bulk terminals. Control efficiencies range from 90 percent to 98 percent depending on the nature of the vapors and the applicable air quality regulations in force.[2]

Emissions from controlled loading operations can be calculated by multiplying the uncontrolled emission rate calculated in equations (1) and (2) by the control efficiency term:

$$\left[1 - \frac{\text{efficiency}}{100}\right]$$

Sample Calculation

Loading losses from a gasoline tank truck in dedicated balance service and practicing vapor recovery would be calculated as follows using equation (1).

Design basis:

Tank truck volume is 8000 gallons
Gasoline RVP is 9 psia
Dispensing temperature is 80°F
Vapor recovery efficiency is 95%

Loading loss equation:

$$L_L = 12.46 \frac{SPM}{T} (1- \frac{eff}{100})$$

where:

S = saturation factor (see Table 4.4-1) = 1.0
P = true vapor pressure of gasoline (see Figure 4.3-8) = 5.6 psia
M = Molecular weight of gasoline vapors (see Table 4.3-3) ≈ 66
T = temperature of gasoline = 540°R
eff = the control efficiency = 95%

$$L_L = 12.46 \frac{(1.0)(5.6)(66)}{540} (1-\frac{95}{100})$$

$$= 0.43 \text{ lbs}/10^3 \text{ gal}$$

Total loading losses are

$$(0.43 \text{ lb}/10^3\text{gal})(8.0\text{x}10^3 \text{ gal}) = 3.4 \text{ lbs of hydrocarbon}$$

Service Stations

Another major source of evaporative hydrocarbon emissions is the filling of underground gasoline storage tanks at service stations. Normally, gasoline is delivered to service stations in large (8000 gallon) tank trucks. Emissions are generated when hydrocarbon vapors in the underground storage tank are displaced to the atmosphere by the gasoline being loaded into the tank. As with other loading losses, the quantity of the service station tank loading loss depends on several variables including the size and length of the fill pipe, the method of filling, the tank configuration, and the gasoline temperature, vapor pressure, and composition. An average hydrocarbon emission rate for submerged filling is 7.3 lbs/10^3 gallons of transferred gasoline and for splash filling is 11.5 lbs/10^3 gallons of transferred gasoline.[2]

Emissions from underground tank filling operations at service stations can be reduced by the use of the vapor balance system (Figure 4.4-5). The vapor balance system employs a vapor return hose which returns gasoline vapors displaced from the underground tank to the tank truck storage compartments being emptied. The control efficiency of the balance system ranges from 93 to 100 percent. Hydrocarbon emissions from underground tank filling operations at a service station employing the vapor balance system and submerged filling are not expected to exceed 0.3 lbs/10^3 gallons of transferred gasoline.

A second source of hydrocarbon emissions from service stations is underground tank breathing. Breathing losses occur daily and are attributed to temperature changes, barometric pressure changes, and gasoline evaporation. The type of service station operation also has a large impact on breathing losses. An average breathing emission rate is 1 lb/10^3 gallons throughput.[2]

Motor Vehicle Refueling

An additional source of evaporative hydrocarbon emissions at service stations is vehicle refueling operations. Vehicle refueling emissions are attributable to vapors displaced from the automobile tank by dispensed gasoline and to spillage. The quantity of displaced vapors is dependent on gasoline temperature, auto tank temperature, gasoline RVP, and dispensing rates. Although several correlations have been developed to estimate losses due to displaced vapors, significant controversy exists concerning these correlations. It is estimated that the hydrocarbon emissions due to vapors displaced during vehicle refueling averages 9 lbs/10^3 gallons of dispensed gasoline.[2]

The quantity of spillage loss is a function of the type of service station, vehicle tank configuration, operator technique, and operation discomfort indices. An overall average spillage loss is 0.7 lb/10^3 gallons of dispensed gasoline.[4]

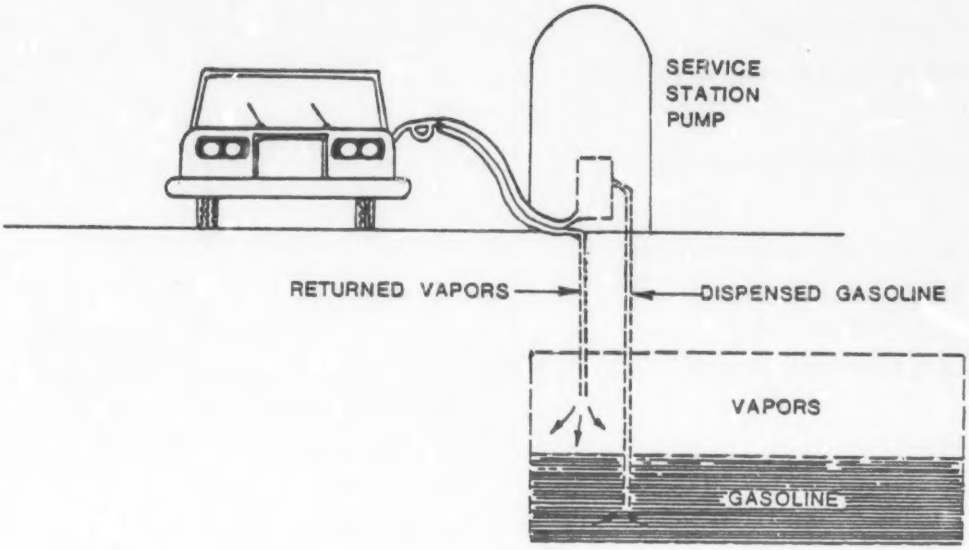
Control methods for vehicle refueling emissions are based on conveying the vapors displaced from the vehicle fuel tank to the underground storage tank vapor space through the use of a special hose and nozzle (Figure 4.4-7). In the "balance" vapor control system the vapors are conveyed by natural pressure differentials established during refueling. In "vacuum assist" vapor control systems the conveyance of vapors from the auto fuel tank to the underground fuel tank is assisted by a vacuum pump. The overall control efficiency of vapor control systems for vehicle refueling emissions is estimated to be 88 to 92 percent.[2]

TABLE 4.4-3

HYDROCARBON EMISSIONS FROM GASOLINE SERVICE STATION OPERATIONS

	Emission Rate	
Emission Source	lb/10^3 gal throughput	kg/10^3 liter throughput
Filling Underground Tank		
Submerged filling	7.3	0.88
Splash filling	11.5	1.38
Balanced submerged filling	0.3	0.04
Underground Tank Breathing	1	0.12
Vehicle Refueling Operations		
Displacement losses (uncontrolled)	9	1.08
Displacement losses (controlled)	0.9	0.11
Spillage	0.7	0.084

FIGURE 4.4 - 7
AUTOMOBILE REFUELING VAPOR-RECOVERY SYSTEM


SERVICE
STATION
PUMP
RETURNED VAPORS
DISPENSED GASOLINE
VAPORS
GASOLINE

REFERENCES
SECTION 4.4

1. American Petroleum Inst., Evaporation Loss Committee, Evaporation Loss From Tank Cars, Tank Trucks, And Marine Vessels, Bull. 2514, Washington, D.C. 1959.

2. Burklin, Clinton E., et al. Study Of Vapor Control Methods For Gasoline Marketing Operations, 2 vols., Austin, Texas, Radian Corporation, May 1975.

3. Scott Research Laboratories, Inc., Investigation Of Passenger Car Refueling Losses, Final Report, 2nd year program, CPA 22-69-69. APRAC Project No. Cape 9-68.

4. Scott Research Laboratories, Inc., Mathematical Expressions Relating Evaporative Emissions From Motor Vehicles To Gasoline Volatility, summary report, API Publication 4077, Plumsteadville, Pennsylvania, March 1971.

ATTACHMENT C

REFINERY LOSSES

Preceding page blank

Table 9.1-1. EMISSION FACTORS FOR PETROLEUM REFINERY PROCESSES

EMISSION FACTOR RATING: A

Type of Process	Particulates	Sulfur oxides (SO_2)	Carbon monoxide	Hydro-carbons	Nitrogen oxides (NO_2)	Alde-hydes	Ammonia
Boilers and process heaters[a]							
lb/10^3 bbl oil burned	840	6,720S[b]	Neg[c]	140	2,900	25	Neg
kg/10^3 liters oil burned	2.4	19.2S	Neg	0.4	8.3	0.071	Neg
lb/10^3 ft^3 gas burned	0.02	2s[d]	Neg	0.03	0.23	0.003	Neg
kg/10^3 m^3 gas burned	0.32	32s	Neg	0.48	3.7	0.048	Neg
Fluid catalytic cracking units[e]							
Uncontrolled							
lb/10^3 bbl fresh feed	242 (93 to 340)[f]	493 (313 to 525)	13,700	220	71.0 (31.1 to 145.0)	19	54
kg/10^3 liters fresh feed	0.695 (0.267 to 0.976)	1.413 (0.898 to 1.505)	39.2	0.630	0.204 (0.107 to 0.416)	0.054	0.155
Electrostatic precipitator and CO boiler							
lb/10^3 bbl fresh feed	44.7 (12.5 to 61.0)	493 (313 to 525)	Neg	220	71.0 (37.1 to 145.0)	19	54
kg/10^3 liters fresh feed	0.128 (0.036 to 0.175)	1.413 (0.898 to 1.505)	Neg	0.630	0.204 (0.107 to 0.416)	0.054	0.155

Type of process	Particulates	Sulfur oxides (SO_2)	Carbon monoxide	Hydro-carbons	Nitrogen oxides (NO_2)	Alde-hydes	Ammonia
Moving-bed catalytic cracking units [a]							
$lb/10^3$ bbl fresh feed	17	60	3,800	87	5	12	6
$kg/10^3$ liters fresh feed	0.049	0.171	10.8	0.250	0.014	0.034	0.017
Fluid coking units [g]							
Uncontrolled							
$lb/10^3$ bbl fresh feed	523	NA[h]	Neg	Neg	Neg	Neg	Neg
$kg/10^3$ liters fresh feed	1.50	NA	Neg	Neg	Neg	Neg	Neg
Electostatic precipitator							
$lb/10^3$ bbl fresh feed	6.85	NA	Neg	Neg	Neg	Neg	Neg
$kg/10^3$ liters fresh feed	0.0196	NA	Neg	Neg	Neg	Neg	Neg
Compressor internal combustion engines [a]							
$lb/10^3$ ft^3 gas burned	Neg	2s	Neg	1.2	0.9	0.1	0.2
$kg/10^3$ m^3 gas burned	Neg	32s	Neg	19.3	14.4	1.61	3.2

---

[a] Reference 1.

[b] S = Fuel oil sulfur content (weight percent): factors based on 100 percent combustion of sulfur to SO_2 and assumed density of 336 lb/bbl (0.96 kg/liter).

[c] Neglibigle emission.

[d] s = refinery gas sulfur content (lb/100 ft^3): factors based on 100 percent combustion of sulfur to SO_2.

[e] References 1 through 6.

[f] Numbers in parenthesis indicate range of values observed.

[g] Reference 3.

Table 9.1-2. EMISSION FACTORS FOR PETROLEUM REFINERY EVAPORATIVE SOURCES
EMISSION FACTOR RATING A

Process Type	Uncontrolled Emissions	Controlled Emissions	Method of Control
Blowdown Systems			Vapor recovery system or flaring.
lb/10^3 bbl refinery capacity	300	5	
kg/10^3 liters refinery capacity	0.86	0.014	
Process Drains & Wastewater Separators			Vapor recovery systems and/or separator covers.
lb/10^3 gal wastewater	5	0.2	
kg/10^3 liters wastewater	0.60	0.024	
lb/10^3 bbl refinery capacity	200	10	
kg/10^3 liters refinery capacity	0.57	0.029	
Vacuum Jets			Fume burner, waste heat boiler, vapor recovery, change to vacuum pumps, surface condenser.
lb/10^3 bbl of vacuum charge	130	Neg	
kg/10^3 liters of vacuum charge	0.37	Neg	
lb/10^3 bbl of refinery capacity	60	Neg	
kg/10^3 liters of refinery capacity	0.17	Neg	
Cooling Towers			Good housekeeping and maintenance.
lb/10^6 gal cooling water	6	3	
lb/10^6 liters cooling water	0.72	0.36	
lb/10^3 bbl refinery capacity	18	10	
kg/10^3 liters refinery capacity	0.051	0.029	
Pipeline Valves and Flanges			Good housekeeping and maintenance.
lb/day-valve	0.15	NA	
kg/day-valve	0.068	NA	
lb/10^3 bbl refinery capacity	28	NA	
kg/10^3 liters refinery capacity	0.080	NA	

Table 9.1-2 (continued)

Process Type	Uncontrolled Emissions	Controlled Emissions	Method of Control
Vessel Relief Valves			Rupture discs up stream of relief valve.
lb/day-valve	2.4	Neg	
kg/day-valve	1.1	Neg	
$lb/10^3$ bbl refinery capacity	11	Neg	
$kg/10^3$ liters refinery capacity	0.031	Neg	
Pump Seals			Mechanical seals, dual seals, purged seals.
lb/day-seal	5	3	
kg/day-seal	2.3	1.4	
$lb/10^3$ bbl refinery capacity	17	10	
$kg/10^3$ liters refinery capacity	0.049	0.029	
Compressor Seals			Mechanical seals, dual seals, purged seals.
lb/day-seal	9	NA	
kg/day-seal	4.1	NA	
$lb/10^3$ bbl refinery capacity	5	NA	
$kg/10^3$ liters refinery capacity	0.014	NA	
Asphalt Blowing			Scrubbing, incineration.
lb/Ton of asphalt	60	Neg	
kg/MT of asphalt	30	Neg	
Blind Changing			Line flushing, use of "line" blinds, blind insulation w/gate valves.
$lb/10^3$ bbl refinery capacity	0.3	Neg	
$kg/10^3$ liters refinery capacity	0.001	Neg	
Sampling			Avoid excessive sample purge, flush sample purge to sump.
$lb/10^3$ bbl refinery capacity	2.3	Neg	
$kg/10^3$ liters refinery capacity	0.007	Neg	

Table 9.1-2 (continued)

Process Type	Uncontrolled Emissions	Controlled Emissions	Method of Control
Other			
lb/10^3 bbl refinery capacity	7	NA	Good Housekeeping and
kg/10^3 liters refinery capacity	0.020	NA	maintenance.

NA Emission factors for these sources are not available.

References:

Atmospheric Emissions from Petroleum Refineries. A Guide for Measurement and Control. PHS No. 763. Washington, D.C., Public Health Service, 1960.

Burklin, C.E., et al., Control of Hydrocarbon Emissions from Petroleum Liquids. Contract No. 68-02-1319, Task 12, EPA 600/2-75-052. PB 246 650/ST. Austin, Texas, Radian Corporation, Sept. 1975.

ATTACHMENT D

PRODUCTION LOSSES

9.3 OIL AND GAS PRODUCTION

The oil and gas production industry is involved in locating and retrieving oil and gas from underground formations and preparing the well streams for use by consumers or refiners. Production activities begin with exploration and end with storage or sales.

The oil and gas production industry comprises five segments:

1) Exploration and Site Preparation - This segment includes those operations necessary for selection and preparation of a drilling site.

2) Drilling - The drilling segment is comprised of all operations involved in digging a well and preparing it for production.

3) Crude Processing - Several process modules are described for preparing crude for refinery use.

4) Natural Gas Processing - This segment includes widely used processes for preparing natural gas for sales.

5) Secondary or Tertiary Recovery - Methods for stimulating well production are included in this segment.

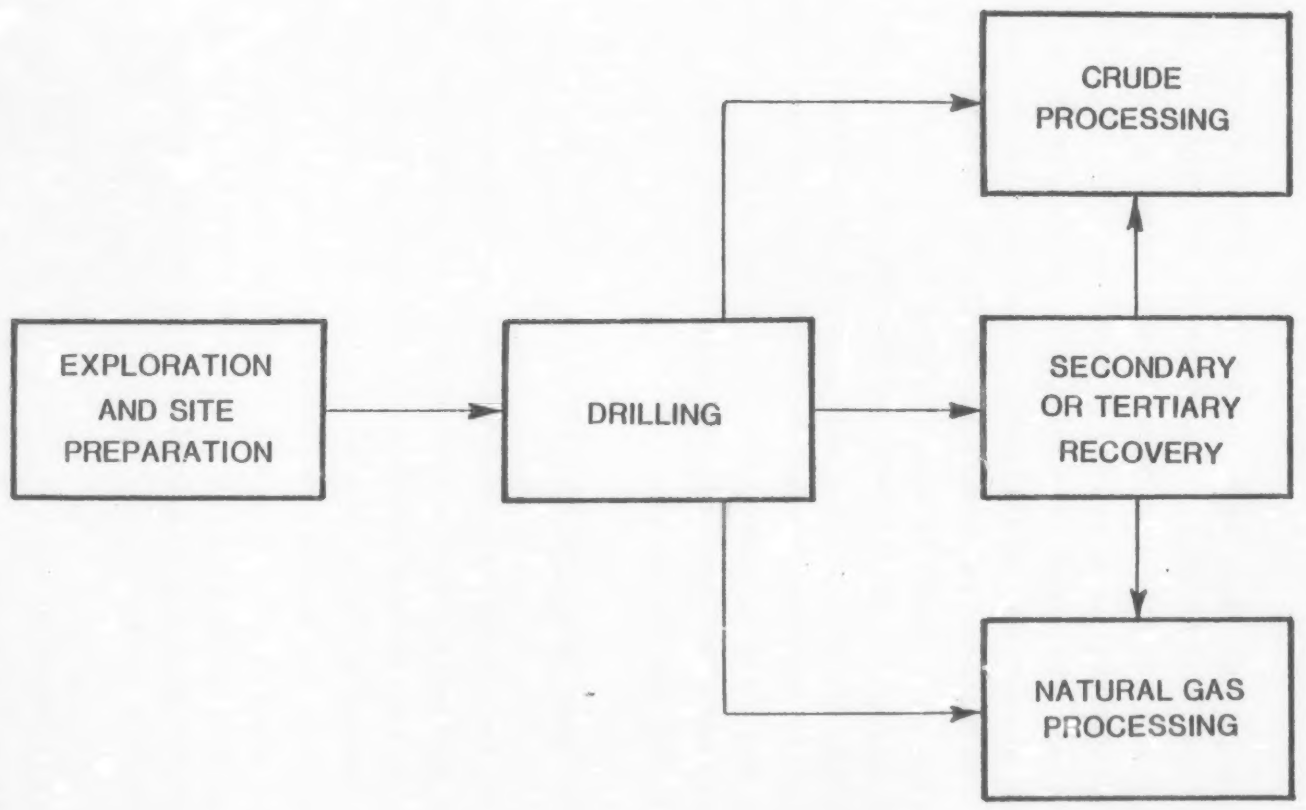
Figure 9.3-1 is a schematic representation of the industry segments and their interrelationships.

An attempt has been made to present processing steps and their emissions in sequence. The problem encountered in the crude processing and natural gas processing segments is the diversity of the operations involved. The sequences of processing steps are not at all the same from place to place; moreover, some processes may be absent and additional processes present to deal with the local conditions and composition of the production. Production process descriptions are further complicated because oil wells often produce significant quantities of natural gas and conversely some gas wells produce significant quantities of crude oils. This emission section cannot be considered an all-encompassing survey, but only a summary of the evaporative hydrocarbon emissions associated with some of the most commonly used methods in domestic oil and gas production.

9.3.1 Exploration and Site Preparation

The objective of oil exploration procedures is defining and describing geological structures which are often associated with oil accumulation in the earth's crust. Geological surveys of the surface are made using aerial photographs, satellite photographs, and mappings of surface outcrops. Offshore geological surveys include mapping of the ocean bottom using acoustic sounding methods. Subsurface geological surveys are made by seismic and gravimetric methods which yield indications of the depth and nature of subsurface rock.

Site preparation activities include those operations necessary to prepare the drilling site and "rig-up" the equipment. The operations are necessarily different for onshore and offshore



EXPLORATION AND SITE PREPARATION
DRILLING
CRUDE PROCESSING
SECONDARY OR TERTIARY RECOVERY
NATURAL GAS PROCESSING

FIGURE 9.3-1. THE OIL AND GAS PRODUCTION INDUSTRY

locations, and will be dictated somewhat by local conditions. For land operations earth-moving machinery clears, grades, and levels the site. Earthen pits are dug for circulating fluids and wastes, and access roads are built and surfaced. Water wells are dug, and the drilling rig and associated machinery are installed. Preparations for offshore drilling differ widely because of the many types of rigs available. The drilling rigs may be floating or fixed in place on the ocean floor. In all cases the pumps, pipelines, and machinery must be installed and in the case of submersible rigs, the platform must be settled firmly on the bottom.

No significant sources of evaporative hydrocarbon emissions are associated with exploration and site preparation segments of the oil and gas production industry. There is a very minimal danger of hydrocarbon emissions due to a blowout during core drilling operations when a shallow pocket of high pressure oil or gas is encountered.

9.3.2 Drilling

Drilling is the process of actually cutting through the earth's crust to form a well and is accomplished by rotating and hoisting operations performed at the derrick. The cutting and grinding through the earth's surface is accomplished by rotating the drill string with the required weight on the drill bit affixed to the end of the drill string. Additional lengths of drill pipe are attached as the drilling proceeds. When a worn drill bit has to be replaced, the entire string of pipe must be hoisted. The pipe lengths are removed as the string is slowly raised until the drill bit is brought to the surface and changed out. The new bit and the drill string are slowly lowered, and the lengths of pipe are replaced until the bottom is reached, at which time rotation begins again. The drill bit is designed to break, dislodge, and fragment formation material. A drilling fluid (mud) is circulated down to the drill bit through the string for the purpose of transporting formation cuttings to the surface for disposal.

Hydrocarbon emissions associated with drilling operations are attributable to oil and gas brought to the surface with drilling mud. Oil brought to the surface is separated and generally disposed of in open pits or pumped into barges for onshore disposal. Excess oil based muds are treated in the same manner. At any point that the oil is open to the air, atmospheric emissions result. Hydrocarbon gas brought to the surface with drilling fluid is separated from the mud and may be vented or flared at a safe distance from the drilling operations. The magnitude of hydrocarbon emissions released from production operations is dependent on product volatility, method of handling and concentration of hydrocarbons returning with the mud. Estimates of these emissions are not available.

9.3.3 Crude Oil Production

The crude oil production industry is involved in locating and retrieving oil from underground formations and preparing the well streams for use by refiners. Crude oil production can be divided into four major steps: (1) extraction, (2) well production gathering, (3) field processing, and (4) storage or sales. These four major steps are applicable to onshore and offshore production operations.

Extraction involves bringing the oil to the surface by natural flow, gas lifting, or pumping. The production from each well is then sent to a complex gathering system to combine all of the production or to separate the individual well productions. Field processing removes water and/or solids and/or gas from the produced oil. Storage at the production site or sale of the crude oil via pipeline, truck, rail, barge, or tanker marks the end of production activities. Figure 9.3-2 gives a schematic flow diagram of the crude oil production industry. All phases of crude oil production involve potential sources of evaporative hydrocarbon emissions.

Extraction

In natural flow production the bottom hole oil reservoir pressure is sufficient to overcome gravity and pressure drop, and the produced oil flows into the gathering system without energy input. Gas lifting is accomplished by injecting gas into the downhole production tubing at various depths in order to assist oil flow to the surface. Most producing oil wells require pumping by mechanical lifting methods using subsurface pumps. The most commonly used pump is the reciprocating sucker rod pump. Electric or hydraulic bottomhole centrifugal pumps may also be used.

The primary source of emissions from extraction operations is the evaporation of crude oil which leaks from reciprocating pump rod seals at the wellhead. This source is absent from natural flow and gas lift operations. Fugitive emissions may occur in gas lifting or gas injection operations if leaks develop in the gas compression and piping system. Emissions from extraction operations can be minimized by proper maintenance of operating equipment and the use of double pump seals.

Well Production Gathering

The produced crude oil enters the production gathering system at the wellhead. The production from wells in the same area is collected and transported to the crude processing units

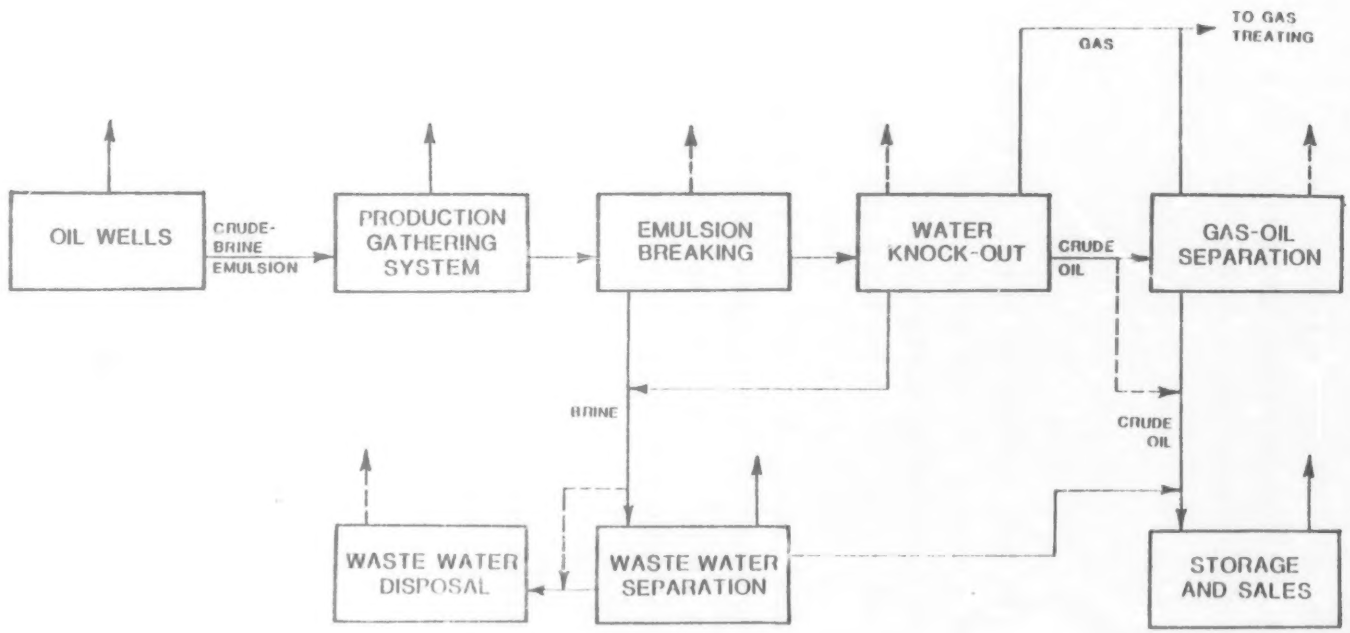

TO GAS TREATING
GAS
OIL WELLS
CRUDE-BRINE EMULSION
PRODUCTION GATHERING SYSTEM
EMULSION BREAKING
WATER KNOCK-OUT
CRUDE OIL
GAS-OIL SEPARATION
BRINE
CRUDE OIL
WASTE WATER DISPOSAL
WASTE WATER SEPARATION
STORAGE AND SALES

FIGURE 9.3-2. FLOWSHEET OF PETROLEUM PRODUCTION OPERATIONS.
(SOURCES OF EVAPORATIVE HYDROCARBON
EMISSIONS ARE INDICATED BY VERTICAL ARROWS).

by a system of pipes, valves, fittings, pumps, and meters. The gathering system may be small if the processing units are small and serve a few localized wells. Large processing units which serve many wells in decentralized areas require more extensive gathering systems. Offshore production gathering systems may transport crude to centrally located offshore processing platforms, or to onshore processing facilities.

Evaporative emissions from the production gathering system are the result of crude oil leaks from valves, fittings, and pumps. The magnitude of these emissions may vary greatly from one facility to another depending on the number of equipment pieces, the physical properties of the crude oil being gathered, and the efficiency of equipment maintenance. Emissions can be reduced by regular maintenance of equipment, relief valve venting to vapor recovery or flare, and conversion of pump seals to mechanical or double seals.

Field Processing

Before crude oil is sent to a refinery, it is processed to remove water, solids, and gas if they are produced with the crude oil. Field processing units vary in size, depending on the number of wells and production rates in the area that the processing unit is located. The sequence of processing steps varies from one production facility to another, and some processes may be absent or additional processes present, depending on the local conditions and the composition of the production. Offshore production may be processed at offshore platform processing units, or it may be piped from the wellhead to onshore processing units.

Water Removal - Produced crude oil nearly always contains water, usually as an oily brine or emulsion, and most of this water must be removed before the crude oil is sent to a refinery. The composition of the production determines the sequence and types of processing used to reduce brine content to about two weight percent.

"Free water knock-out" - Water that is produced with crude oil may be in the form of an immiscible brine. Free water knock-out is the settling out of this water in a large tank usually equipped with baffles to minimize turbulence and mixing. Suspended solids can also be removed in this processing step. The rate of throughput is determined by the settling characteristics of the produced free water. These units usually operate at ambient temperatures and atmospheric pressure, although free water knock-out in conjunction with gas separation or heat treating will operate at varying conditions. The input is well production, and yields are determined by the composition of the production. The output is oil or emulsion, gas, oily brine, and removed solids.

"Emulsion breaking" - The relative amounts of free water and emulsion determine whether free water knock-out or emulsion breaking is the upstream process. Emulsion breaking consists of destabilization of the film between the oil and water droplets, coalescence of the oil droplets, and gravitational separation of the oil and water phases. The four methods used in dehydrating emulsions are heating, chemical destabilization, electrical coalescense, and gravitational settling.

Heater treaters are commonly used for emulsion breaking. They are usually direct fired, although indirect fired heater treaters are also available. The brine-oil emulsion is destabilized by the application of heat. Heater treaters are normally operated at 210°F (99°C) under varying pressures, with a residence time of about twenty minutes. These conditions may change if the heater treater is also a gas separator (three phase separator). The input is brine-oil emulsion and separated oil, gas, oily brine, and solids are the output.

Chemical destabilization causes emulsions to break up by altering the chemical compositions at the interfacial film and by the effects of surface-active agents. Separation can be enhanced by addition of heat and is completed in some type of gravity settler.

Electrical dehydrators consist of a preheater to reduce the viscosity of the crude, followed by exposure of the crude to a high-voltage alternating electrical field. When the polar water molecules in the emulsion turn to follow the lines of the electrical field, the molecules coalesce and form droplets which fall out by the force of gravity. Electrical dehydrators may operate at varying temperatures and pressures, with a residence time of about twenty minutes. The input is brine-oil emulsion and the output is separated oil, gas, and oily brine.

Gravitational settling can be used to break unstable emulsions. This is similar to free water knock-out, except that the emulsion requires a longer residence time to achieve separation. Gravitational settling is usually done in a wash tank which has three parts: (1) a bulk separator for free gas, (2) a bulk separator for free water, and (3) a quiescent tank for settling of suspended solids and water droplets. Operating conditions, inputs, yields and outputs are essentially the same as those for free water knock-out.

Oil-Gas Separation - Crude oil contains some amount of entrained and dissolved gases, and this amount varies from very low gas-oil ratios to gas-oil ratios that are so high that the well is classified as a gas well with entrained oil. Separation of gases from the oil is usually accomplished at the production site. Nonsolution gases can be separated by settling, agitating, heating, or adding chemicals. The shape of separators is determined by the gas-oil ratio. For high gas-oil ratios horizontal cylindrical separators are used, and for low gas-oil ratios vertical cyclindrical separators are used. Spherical separators are used for intermediate gas-oil ratios. In two-phase separators only oil and gas are separated, while three-phase units separate oil, gas, and water. The type of internal equipment used to achieve separation is dependent on the composition of the production. When wellhead pressure is very high, a stage separation procedure may be used in which a series of separators are operated to perform two or more flash vaporizations at sequentially reduced pressures.

The rate of throughput is determined by the characteristics of the production. Residence times of one to three minutes are generally adequate, but difficult separations may require five to twenty minutes. The operating temperature and pressure of separators will generally begin with the wellhead temperature and pressure and will drop step-wise to ambient conditions. Inputs are gas-oil or gas-oil-water mixtures, and yields are determined by the gas-oil ratio and operating conditions. Outputs are gas, oil, and in the case of three-phase separators, water. The crude product is sent to storage or sales, and the gas produced is sent to a gas processing plant, or in remote areas it may be vented, re-injected, or flared.

Waste Water Disposal - The oily brine from the knock-out tanks, dehydrators, and three-phase separators must be further treated before being discharged as wastewater or reinjected into a waterflooding or disposal well. The flotation cell type wastewater treater is a commonly used primary water treating facility. Other wastewater treatment methods include sedimentation followed by aeration, aerated lagoons, or evaporation ponds. Most wastewater treaters operate at ambient conditions, but some flotation cells may have a gas solution tank that operates at 2-3 atmospheres of pressure. Flotation cells have skimmers that recover the oil and scrapers which remove settled solids. Aerated lagoons and evaporation ponds dispose of waste brine and oil by solar evaporation.

Emissions and Controls - Field processing units require a system of pipes, fittings, pumps, compressors, and valves to transport the processed fluids. Leaks in this system are a potential source of evaporative hydrocarbon emissions. Water removal units can emit hydrocarbons if they are not vapor tight vessels, especially if heater treaters are used, since the added heat increases the vapor pressure of the crude oil. Gas-oil separators are usually connected to gas recovery systems and should not be a major source of hydrocarbon emissions. In remote areas or where it is uneconomical to send the gas to a recovery system, the gas may be flared or vented. Flotation cells can emit hydrocarbons from evaporation of the oil that floats to the surface. Wastewater lagoons and evaporation ponds will evaporate any oil that is discharged with the wastewater. In remote locations the oil that floats to the surface of the evaporation ponds may be burned.

Evaporative hydrocarbon emissions from field processing units can be reduced with proper maintenance of equipment, and (1) rupture discs and vapor recovery or flares for relief valves, (2) mechanical or double seals for pumps and compressors, and (3) floating covers or sealed vapor recovery systems for wastewater separators.

Storage and Sales

Evaporative emissions and emission factors for crude oil in storage are presented in Section 4.3. Section 4.4 presents emissions and emission factors for crude oil in transportation and marketing operations.

Emission Factors

Evaporative emissions from crude oil production operations may vary significantly from one location to another. There is not sufficient field test data available on oil production operations to allow accurate estimation of emission factors for all types of production facilities. The Monterey-Santa Cruz County Unified Air Pollution Control District has published data for emissions from production operations in Monterey County, California. "Air Pollution in Monterey and Santa Cruz Counties" present emission data based on $18.5x10^6$ bbl of crude oil production in 1967. Table 9.3-1 gives emission factors based on the data in the Monterey County study.[7]

In the Monterey County survey, emissions from pump seals were found to average 75 $lb/10^3$ bbl of crude production.[3] In a 1958 survey of Los Angeles area refineries the average emission rate for pump seals was 17 $lb/10^3$ bbl of refinery capacity.[3] This data indicates that although an emission factor of 75 $lb/10^3$ bbl of crude production may be representative of an average

TABLE 9.3-1

ESTIMATED CRUDE OIL PRODUCTION EMISSION FACTORS

Point Source	Emission Factor[1] (lb/10^3 bbl crude production)
Compressor seals	4
Relief valves	8
Waste water separators	8
Pipeline valves	12
Pumps	75

---

[1] Based on 18.5×10^6 bbl/year crude production in Monterey County, California in 1967. Reference 7.

production facility in 1967, the evaporative emissions from pump seals in production operations may be as low as 17 lb/10^3 bbl of crude throughput with the application of newer technology and proper maintenance scheduling. The Monterey County data shows a total evaporative emission rate from crude oil production operations of 107 lb/10^3 bbl of crude production.[7] This emission rate does not include evaporative emissions from storage facilities.

Crude oil production facilities can vary from older fields where production rates may be too low to economically support regular maintenance of obsolete equipment, to new fields where modern equipment with emission control devices and regular maintenance are used. Many crude oil production units are similar to petroleum refinery units. Section 9.1 on refinery emissions lists emission factors for evaporative sources in petroleum refining. These emission factors may be used to estimate emissions from crude oil production operations for similar unit operations, such as pipeline valves etc. Emission factors are given for individual operations in units of lb/valve day, etc. A detailed flow diagram of the production operations is required in order to make accurate emission estimates from this basis.

9.3.4 Natural Gas Processing

The natural gas processing segment of the oil and gas production industry is involved in the preparation of natural gas for sales. Natural gas as obtained from the gas well may contain impurities, including water vapor, carbon dioxide, suflur compounds, and hydrocarbon liquids. These impurities must be removed in order for natural gas to meet the quality regulations for pipeline sales.

The processes used to meet these sales requirements are presented in this section. Although the processing steps are presented sequentially in Figure 9.3-3, they are by no means intended to be in a prescribed order. Variations in sequences, operating conditions, and physical locations occur throughout the industry with local production conditions and geographical locations dictating the particular processing methods.

Liquid Hydrocarbon Recovery

From the gas well, natural gas may first be routed to a liquid hydrocarbon recovery unit for the removal of readily separable water and hydrocarbon liquids. High levels of water vapor and hydrocarbon liquids in natural gas present the potential hazards of condensation and freezing, which may interrupt the transportation of gas to the gas plant. The removal of entrained water and hydrocarbon liquid droplets is effected by the use of mist eliminators and knockout chambers. If additional pretreatment is necessary, there are four major types of liquid recovery processes which may be used singly or in combination to effect the necessary separation; adsorption, absorption, refrigeration, and compression. One of the newer technologies involves the use of a turboexpander to expand the natural gas through a turbine compressor from which it exhausts at extremely low temperatures; most of the gas except methane is condensed. These liquid recovery technologies are discussed in detail under the section on product separation. Water separated in the liquid hydrocarbon recovery unit is sent to disposal, and hydrocarbon condensates are sent to the product separation unit for further separation into salable products.

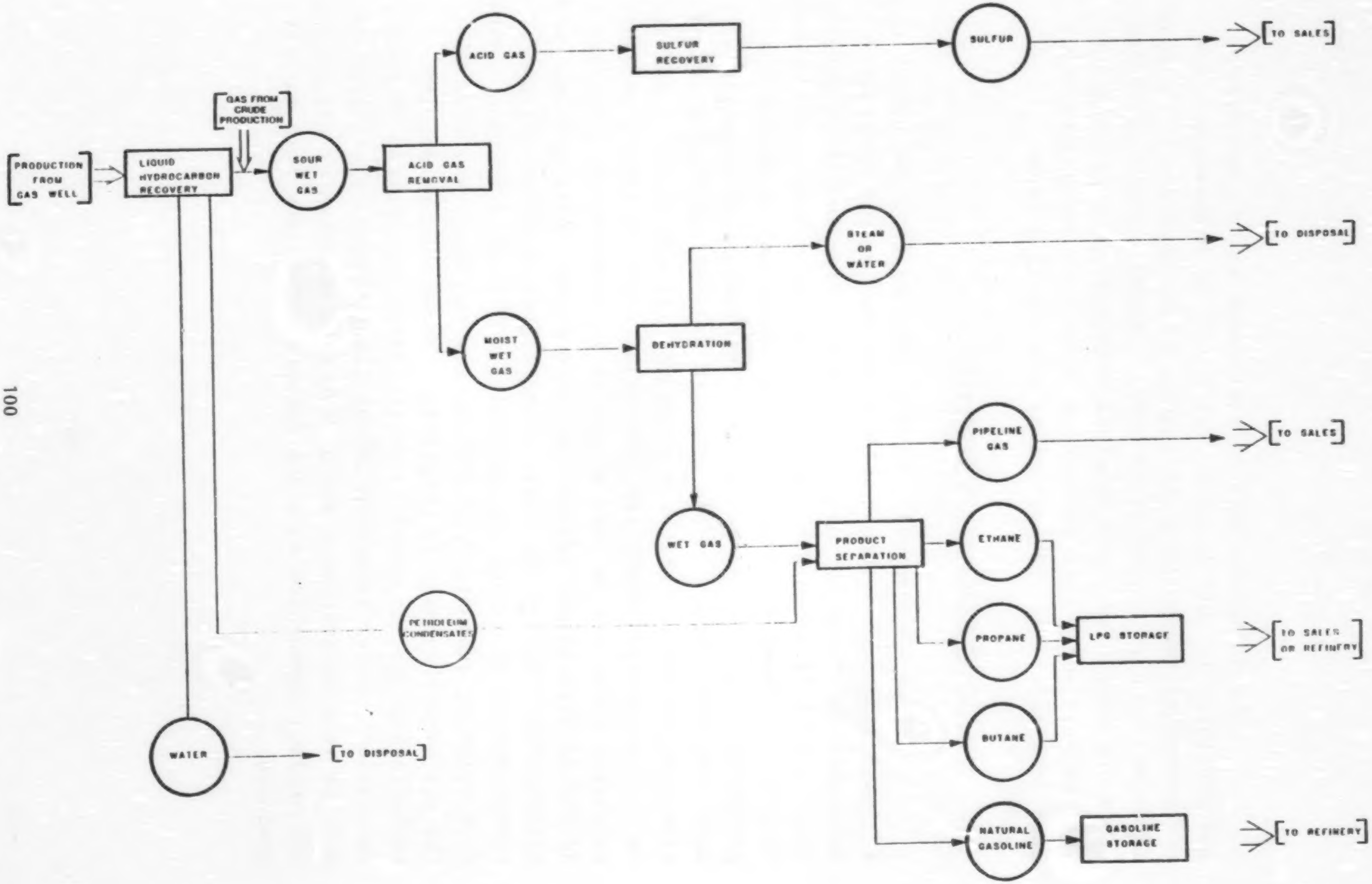

PRODUCTION FROM GAS WELL
LIQUID HYDROCARBON RECOVERY
GAS FROM CRUDE PRODUCTION
SOUR WET GAS
ACID GAS REMOVAL
ACID GAS
SULFUR RECOVERY
SULFUR
TO SALES
MOIST WET GAS
DEHYDRATION
STEAM OR WATER
TO DISPOSAL
WET GAS
PRODUCT SEPARATION
PIPELINE GAS
TO SALES
ETHANE
PROPANE
BUTANE
LPG STORAGE
TO SALES OR REFINERY
NATURAL GASOLINE
GASOLINE STORAGE
TO REFINERY
PETROLEUM CONDENSATES
WATER
TO DISPOSAL

FIGURE 9.3-3 GAS PROCESSING FLOW DIAGRAM

Acid Gas Removal

The acid gas removal unit is designed to remove hydrogen sulfide from hydrocarbon gases by absorption in an aqueous, regenerative sorbent. Amine-based sorbents are the most commonly used. Within the acid gas removal unit, the natural gas feed is contacted with the amine sorbent in an absorption column to selectively absorb H_2S from the natural gas. Other gaseous species which will also be absorbed if present include: carbon dioxide, nitrogen, mercaptans, and some hydrocarbons. Absorbed gases are steam stripped or distilled from the amine sorbent in a regeneration step. The products are a "sweet" natural gas and a concentrated hydrogen sulfide stream. Hydrogen sulfide is normally routed to a sulfur recovery plant for recovery of its sulfur content. However, if a sulfur recovery plant is not available, the hydrogen sulfide is flared to produce less toxic sulfur oxides.

Sulfur Recovery

The sulfur recovery unit converts hydrogen sulfide to elemental sulfur by the Claus process. The Claus process involves the combustion of 1/3 of the hydrogen sulfide feed to sulfur dioxide, followed by the catalytic conversion of the remaining hydrogen sulfide and sulfur dioxide to elemental sulfur and water. The elemental sulfur is marketed, and the water is routed to disposal.

Dehydration

The dehydration unit removes water vapor from natural gas so that it will meet market specifications. The most common dehydration process used in natural gas production is based upon the absorption of water from natural gas into a di- or tri-ethylene glycol sorbent. The glycol sorbent is regenerated by distilling off the water. Other dehydration processes frequently used include adsorption with molecular sieves and dessicants, absorption with hygroscopic materials, and condensation using refrigeration.

Product Separation

Purified natural gas laden with hydrocarbon liquids, and petroleum condensates separated from the well head gas are processed in a product separation unit for the recovery of valuable hydrocarbon liquids. The products from the product separation unit include: 1) pipeline gas which is almost pure methane, 2) ethane, 3) propane, 4) butane, and 5) natural gasoline, which is a blend of all hydrocarbons heavier than butane.

There are several different methods used to achieve product separation. Commonly used processes involve absorption, refigerated absorption, refigeration, compression, and/or adsorption.

In an absorption process the wet field gas is contacted with an absorber oil in a packed or bubble tray column. Propane and heavier hydrocarbons are absorbed by the oil, while most of the ethane and methane pass through the absorber. The enriched absorber oil is then taken to a stripper where the absorbed propane and heavier compounds are stripped from the oil.

The natural gas feed to a refrigerated absorption process must be dehydrated to a minus 40°C dew point prior to entering the unit. All hydrocarbons except methane are absorbed by absorber oil operating at this temperature. These absorbed hydrocarbons and the oil are passed through a series of fractionation columns from which ethane, propane, and heavier hydrocarbons are removed as product streams.

In refrigeration, a cryogenic process, the natural gas is passed through a heat exchanger where it is cooled to minus 37°C. Condensed hydrocarbons are removed in a gas-liquid separator. The gas from the separator is cooled to minus 93°C and passed through a second separator where more condensed liquids drop out. The liquids from the two separators are fed into a series of distillation columns where methane, ethane, propane, butanes, natural gasoline, and other products are recovered.

A compression process uses two stages of compression, each followed by cooling and gas-liquid separation, to produce a wet natural gas product and natural gasoline. This is not a widely used process.

The adsorption processes consist of two or more beds of activated carbon. The beds are used alternatively, with one or more beds on stream while the others are being regenerated. The activated carbon adsorbs all hydrocarbons except methane. The bed is regenerated by means of heat and steam, which remove the adsorbed hydrocarbons as a vapor. This vapor is then condensed permitting the water to be separated from the liquid hydrocarbons. The resulting hydrocarbon product is fed to a fractionation process where the various components are separated.

Product Storage

The products from the gas processing operations are routed to intermediate storage facilities to await transportation to refineries, petrochemical plants and domestic consumers. Pressure tanks are used to store ethane, propane, and butane. Floating roof tanks and fixed roof tanks are normally used to store natural gasoline. The design and functions of tankage facilities are discussed in detail in Chapter 4.3. Natural gas is not normally stored at gas processing facilities, but compressed and transferred directly into distribution pipelines.

Emissions

The only direct process-source of hydrocarbon emissions from natural gas processing is the water vapor stream vented from a glycol dehydration unit. Small quantities of glycol are distilled from the dehydration process in conjunction with the water distillation step and appear in the vented water vapor. The estimated level of glycol loss from a dehydration unit is 0.1 gal/10^6 SCF of natural gas treated (13.4 liter/10^6 Nm^3).[9]

Fugitive emissions from numerous leaks and spills are collectively the largest source of hydrocarbon emissions from gas processing plants. Sources of fugitive emissions include control valves, relief vales, spills, pipe fittings, pump seals, and compressor seals. Because the rate of fugitive emissions is dependent on processing schemes, housekeeping practices, and maintenance practices, they vary greatly from facility to facility and are difficult to determine. Estimates for the level of fugitive emissions from the standard natural gas processing plant range from 150 to 200 lbs/10^6 SCF of natural gas processed (2400 to 3200 Kg/10^6 Nm^3).[6,9]

Many of the fugitive emission sources composing a natural gas processing unit are analogous to fugitive emission sources found in the refinery. In a survey of Los Angeles area refineries the average leak rate for a control valve in gaseous service was 0.49 lbs/day-valve. In the same refinery survey hydrocarbon leaks from pressure relief valves on operating units averaged 2.9 lbs/day-valve, while single and dual pressure relief valves on storage vessels average 0.32 lbs/day-valve and 1.24 lbs/day-valve, respectively. In another refinery survey of seals in gaseous service emissions from mechanical seals on centrifugal pumps averaged 9.2 lbs/day-seal; emissions from packed seals on centrifugal pumps averaged 10.3 lbs/day-seal; and emissions from packed seals on reciprocating pumps averaged 16.1 lbs/day-seal. Estimates of fugitive emission rates from other gas processing units which are analogous to refinery processing units can be obtained from Section 9.1 on refinery emission sources.[3]

9.3.5 Secondary and Tertiary Recovery

When a producing well decreases its production, it is often stimulated by using secondary and tertiary recovery techniques. The problems causing loss of production fall into three major areas. One major problem, loss of formation pressure, is solved by displacement processes. Displacement processes involve the injection of water or gas under high pressure into the formation to maintain formation pressure. A second problem, low permeability of the formation, occurs when the formation is packed so tightly that the oil cannot flow through it. This is corrected by acid treatment in carbonate rock formations or by formation fracturing with pressurized fluids in sandstone formations. The third major problem occurs when the oil is too viscous to flow easily. This problem is corrected by thermal treatment which increases production by heating the oil via processes such as steam injection, hot water injection, and in-situ combustion.

Secondary and tertiary recovery techniques do not significantly increase the fugitive hydrocarbon emissions generated by standard oil and gas production operations.

9.3.6 Offshore Facilities

Offshore production and processing operations are very similar in principle to their onshore counterparts. However, these facilities tend to be newer installations employing better processing and emission control technology. In addition, because fugitive leaks and spills present a great fire hazard to the high density of processing equipment on off-shore production platforms, good housekeeping and maintenance practices are routinely employed as a safety measure.

REFERENCES
SECTION 9.2

1. Cavanaugh, E.C., et al., Atmospheric Environmental Problem Definition of Facilities For Extraction, On-site Processing, and Transportation of Fuel Resources, Contract No. 68-02-1319, Task 19., Austin, Texas, Radian Corporation, July 1975.

2. Chilingar, George V. and Carrol M. Beeson. Surface Operations in Petroleum Production, N.Y., American Elsevier, 1969.

3. Danielson, John A., comp. and ed., Air Pollution Engineering Manual, 2nd ed., AP-40. Research Triangle Park, N.C., EPA Office of Air & Water Programs, 1973.

4. Environmental Conservation, Washington D.C., National Petroleum Council, 1972.

5. Frick, Thomas C. and R. William Taylor, eds., Petroleum Production Handbook, 2 vols., N.Y., McGraw-Hill, 1962.

6. Monsanto Research Corp., Overview Matrix, Contract No. 68-02-1874, Dayton, Ohio, July 1975.

7. MSA Research Corp., Hydrocarbon Pollutant Systems Study, Vol. 1, Stationary Sources, Effects and Control, PB-219-073, APTD 1499, Evans City, PA., 1972.

8. Petroleum Extension Service, Univ. of Texas, Treating Oil Field Emulsions, 3rd ed., Austin, Texas, 1974.

9. Processes Research, Inc., Industrial Planning & Research, Screening Report, Crude Oil and Natural Gas Production Processes, Final Report, Contract No. 68-02-0242, Cincinnati, Ohio, 1972.

REFERENCES

SECTION 9.2

Continued

10. Reid, G. W., et al., Brine Disposal Treatment Practices Relating to the Oil Production Industry, Program 14020 FVW, EPA 660/2-74-037, Norman, Oklahoma, Univ. Oklahoma Research Inst., 1974.

ATTACHMENT E

SOURCE CLASSIFICATION CODES

REVISED SCC LISTINGS

Fixed Roof	Source	Part	SO_x	NO_x	HC	CO	Units	Action
4-03-001-01	Breath-Gasoline < 100,000 bbl	0	0	0	84.0	0	1000 gal. storage capacity	1
4-03-001-02	Breath-Crude < 100,000 bbl	0	0	0	23.4	0	1000 gal. storage capacity	1
4-03-001-03	Working-Gasoline	0	0	0	8.2	0	1000 gal. throughput	4
4-03-001-04	Working-Crude	0	0	0	2.8	0	1000 gal. throughput	4
4-03-001-05	Breath-JP-4 < 100,000 bbl	0	0	0	31.4	0	1000 gal. storage capacity	1
4-03-001-06	Breath-Jet Kero < 100,000 bbl	0	0	0	1.6	0	" " " "	1
4-03-001-07	Breath-Dist No. 2 < 100,000 bbl	0	0	0	1.4	0	" " " "	1
4-03-001-08	Breath-Benzene	0	0	0	28.8	0	" " " "	4
4-03-001-09	Breath-Cyclohexane	0	0	0	31.0	0	" " " "	4
4-03-001-10	Breath-Cyclopentane	0	0	0	58.4	0	" " " "	*
4-03-001-11	Breath-Heptane	0	0	0	11.3	0	" " " "	*
4-03-001-12	Breath-Hexane	0	0	0	32.1	0	" " " "	*
4-03-001-13	Breath-Isooctane	0	0	0	13.9	0	" " " "	*
4-03-001-14	Breath-Isopentane	0	0	0	142.0	0	" " " "	*
4-03-001-15	Breath-Pentane	0	0	0	94.9	0	" " " "	*
4-03-001-16	Breath-Toluene	0	0	0	12.8	0	" " " "	4
4-03-001-17	Breath-Naphtha	0	0	0		0	" " " "	+
4-03-001-18	Breath-Reformate	0	0	0		0	" " " "	+
4-03-001-19	Breath-Alkylate	0	0	0		0	" " " "	+
4-03-001-20	Breath-Gas Oil	0	0	0		0	" " " "	+
4-03-001-21	Breath-Resid No. 2<100,000 bbl	0	0	0	0.06	0	" " " "	2
4-03-001-22	Breath-LPG	0	0	0		0	" " " "	+
4-03-001-23	Breath-Gasoline > 100,000 bbl	0	0	0	62.1	0	" " " "	3
4-02-001-24	Breath-Crude > 100,000 bbl	0	0	0	16.8	0	" " " "	3
4-02-001-25	Breath-JP-4 > 100,000 bbl	0	0	0	22.6	0	" " " "	3

REVISED SCC LISTINGS

Fixed Roof (cont.)	Source	Part	SO_x	NO_x	HC	CO	Units	Action
4-03-001-26	Breath-Jet Kero > 100,000 bbl	0	0	0	1.1	0	1000 gal. storage capacity	3
4-03-001-27	Breath-Dist No. 2 > 100,000 bbl	0	0	0	0.10	0	" " " "	3
4-03-001-28	Breath-Resid No. 6 > 100,000 bbl	0	0	0	0.005	0	" " " "	3
4-03-001-50	Working-JP-4	0	0	0	2.5	0	1000 gal. throughput	1
4-03-001-51	Working-Jet Kero	0	0	0	0.027	0	" " "	1
4-03-001-52	Working-Dist No. 2	0	0	0	0.023	0	" " "	4
4-03-001-53	Working-Benzene	0	0	0	2.2	0	" " "	4
4-03-001-54	Working-Cyclohex	0	0	0	2.4	0	" " "	4
4-03-001-55	Working-Cyclopent	0	0	0	6.40	0	" " "	*
4-03-001-56	Working-Heptane	0	0	0	1.20	0	" " "	*
4-03-001-57	Working-Hexane	0	0	0	3.60	0	" " "	*
4-03-001-58	Working-Isooctane	0	0	0	1.50	0	" " "	*
4-03-001-59	Working-Isopent	0	0	0	15.7	0	" " "	*
4-03-001-60	Working-Pentane	0	0	0	10.6	0	" " "	*
4-03-001-61	Working-Toluene	0	0	0	0.66	0	" " "	4
4-03-001-62	Working-Naphtha	0	0	0		0	" " "	+
4-03-001-63	Working-Reformate	0	0	0		0	" " "	+
4-03-001-64	Working-Alkylate	0	0	0		0	" " "	+
4-03-001-65	Working-Gas Oil	0	0	0		0	" " "	+
4-03-001-66	Working-Resid No. 6	0	0	0	0.0002	0	" " "	5
4-03-001-67	Working-LPG	0	0	0		0	" " "	+
4-03-001-98	Breath Specify						1000 gal. storage capacity	*
4-03-001-99	Working Specify						1000 gal. throughput	*

REVISED SCC LISTINGS

Floating Roof	Source	Part	SO_x	NO_x	HC	CO	Units	Action
4-03-002-01	Standing STG-Gasoline <100,000 bbl	0	0	0	12.0	0	1000 gal storage capacity	1
4-03-002-02	Working-Gasoline <100,000 bbl	0	0	0	0.023	0	1000 gal throughput	1
4-03-002-03	Standing STG-Crude <100,000 bbl	0	0	0	4.38	0	1000 gal storage capacity	1
4-03-002-04	Working-Crude	0	0	0		0	1000 gal throughput	*
4-03-002-05	Standing STG-JP-4 <100,000 bbl	0	0	0	4.38	0	1000 gal storage capacity	1
4-03-002-06	Standing STG-Jet Kero <100,000 bbl	0	0	0	0.197	0	" " " "	1
4-03-002-07	Standing STG-Dist.No.2 <100,000 bbl	0	0	0	0.179	0	" " " "	1
4-03-002-08	Standing STG-Benzene	0	0	0	4.02	0	" " " "	4
4-03-002-09	Standing STG-Cyclohex	0	0	0	4.38	0	" " " "	4
4-03-002-10	Standing STG-Cyclopen	0	0	0	8.76	0	" " " "	*
4-03-002-11	Standing STG-Heptane	0	0	0	1.64	0	" " " "	*
4-03-002-12	Standing STG-Hexane	0	0	0	4.75	0	" " " "	*
4-03-002-13	Standing STG-Isooctane	0	0	0	2.01	0	" " " "	*
4-03-002-14	Standing STG-Isopentane	0	0	0	20.8	0	" " " "	*
4-03-002-15	Standing STG-Pentane	0	0	0	13.9	0	" " " "	*
4-03-002-16	Standing STG-Toluene	0	0	0	1.75	0	" " " "	4
4-03-002-17	Standing STG-Naphtha	0	0	0		0	" " " "	+
4-03-002-18	Standing STG-Reformate	0	0	0		0	" " " "	+
4-03-002-19	Standing STG-Alkylate	0	0	0		0	" " " "	+
4-03-002-20	Standing STG-Gas Oil	0	0	0		0	" " " "	+

REVISED SCC LISTINGS

Floating Roof Cont.	Source	Part	SO_x	NO_x	HC	CO	Units	Action
4-03-002-21	Standing STG-Resid No. 6 <100,000 bbl	0	0	0	0.007	0	1000 gal storage capacity	2
4-03-002-22	Standing STG-Gasoline >100,000 bbl	0	0	0	6.94	0	" " "	3
4-03-002-23	Working-Gasoline >100,000 bbl	0	0	0	0.013	0	1000 gal throughput	3
4-03-002-24	Standing STG-Crude >100,000 bbl	0	0	0	2.08	0	1000 gal storage capacity	3
4-03-002-25	Standing STG-JP-4 >100,000 bbl	0	0	0	2.48	0	" " "	3
4-03-002-26	Standing STG-Jet Kero >100,000 bbl	0	0	0	0.113	0	" " "	3
4-03-002-27	Standing STG-Dist. No. 2 >100,000 bbl	0	0	0	0.102	0	" " "	3
4-03-002-28	Standing STG-Resid No. 6 >100,000 bbl	0	0	0	0.004	0	" " "	3
4-03-002-99	Standing STG-Capacity	0	0	0		0	" " "	*

REVISED SCC LISTINGS Continued

Variable Vapor Space	Source	Part.	SO_x	NO_x	HC	CO	Units	Action
4-03-003-02	Working-Gasoline	0	0	0	7.7	0	1000 gal throughput	4
4-03-003-03	Working-JP-4	0	0	0	2.3	0	" " "	1
4-03-003-04	Working-Jet Kero	0	0	0	0.025	0	" " "	1
4-03-003-05	Working-Dist. No. 2	0	0	0	0.022	0	" " "	4
4-03-003-06	Working-Benzene	0	0	0	2.1	0	" " "	4
4-03-003-07	Working-Cyclohex	0	0	0	2.3	0	" " "	4
4-03-003-08	Working-Cyclopent	0	0	0	7.2	0	" " "	*
4-03-003-09	Working-Heptane	0	0	0	1.4	0	" " "	*
4-03-003-10	Working-Hexane	0	0	0	4.0	0	" " "	*
4-03-003-11	Working-Isooctane	0	0	0	1.7	0	" " "	*
4-03-003-12	Working-Isopentane	0	0	0	17.8	0	" " "	*
4-03-003-13	Working-Pentane	0	0	0	12.0	0	" " "	*
4-03-003-14	Working-Toluene	0	0	0	0.62	0	" " "	4
4-03-003-15	Working-Resid No. 6	0	0	0	0.0002	0	" " "	3
4-03-003-99	Working-Specify	0	0	0		0	" " "	*

REVISED SCC LISTINGS Continued

Fixed Roof Breathing (Petrochemical)	Source	Part.	SO_x	NO_x	HC	CO	Units	Activity
4-04-001-04	Breath-Acetone	0	0	0	43.8	0	1000 gal storage capacity	5
4-04-001-06	Breath-Acrylonitrile	0	0	0	21.9	0	" " " "	5
4-04-001-14	Breath-Carbon Tetrachloride	0	0	0	62.1	0	" " " "	5
4-04-001-15	Breath-Chloroform	0	0	0	76.7	0	" " " "	5
4-04-001-19	Breath-1,2-Dichloroethane	0	0	0	31.8	0	" " " "	5
4-04-001-26	Breath-Ethylacetate	0	0	0	30.3	0	" " " "	5
4-04-001-28	Breath-Ethylalcohol	0	0	0	10.2	0	" " " "	5
4-04-001-39	Breath-Menthyl Alcohol	0	0	0	13.1	0	" " " "	5
4-04-001-42	Breath-Methylene Chloride	0	0	0	113	0	" " " "	5
4-04-001-43	Breath-Methyl Ethyl Ketone	0	0	0	26.6	0	" " " "	5
4-04-001-44	Breath-Methylmethacrylate	0	0	0	13.9	0	" " " "	5
4-04-001-50	Breath-Isopropylalcohol	0	0	0	11.3	0	" " " "	5
4-04-001-55	Breath-1,1, 1 Trichloroethane	0	0	0	62.1	0	" " " "	5
4-04-001-56	Breath-Trichloroethylene	0	0	0	40.2	0	" " " "	5
4-04-001-58	Breath-Vinyl Acetate	0	0	0	33.6	0	" " " "	5

REVISED SCC LISTINGS Continued

Fixed Roof Working (Petrochemical)	Sources	Part.	SO_x	NO_x	HC	CO	Units	Activity[a]
4-04-005-04	Working-Acetone	0	0	0	4.0	0	1000 gal throughput	5
4-04-005-06	Working-Acrylonitrile	0	0	0	1.8	0	" " "	5
4-04-005-14	Working-Carbon tetrachloride	0	0	0	5.2	0	" " "	5
4-04-005-15	Working-Chloroform	0	0	0	7.1	0	" " "	5
4-04-005-19	Working-1,2-Dichloroethane	0	0	0	2.4	0	" " "	5
4-04-005-26	Working-Ethlacetate	0	0	0	2.3	0	" " "	5
4-04-005-28	Working-Ethylalcohol	0	0	0	0.66	0	" " "	5
4-04-005-39	Working-Methylalcohol	0	0	0	1.1	0	" " "	5
4-04-005-42	Working-Methylene Chloride	0	0	0	11.0	0	" " "	5
4-04-005-43	Working-Methyl Ethyl Ketone	0	0	0	2.1	0	" " "	5
4-04-005-44	Working-Methylmethacrylate	0	0	0	0.72	0	" " "	5
4-04-005-50	Working-Isopropyl Alcohol	0	0	0	0.72	0	" " "	5
4-04-005-55	Working-1,1,1-Trichloroethane	0	0	0	5.1	0	" " "	5
4-04-005-56	Working-Trichloroethylene	0	0	0	2.8	0	" " "	5
4-04-005-58	Working-Vinyl Acetate	0	0	0	2.7	0	" " "	5

REVISED SCC LISTINGS

Floating Roof Standing (Petrochemical)	Source	Part	SO×	NO×	HC	CO	Units	Action
4-04-010-04	Standing-Acetone	0	0	0	6.2	0	1000 gal. storage capacity	5
4-04-010-06	Standing-Acrylonitrile	0	0	0	3.1	0	" " " "	5
4-04-010-14	Standing-Carbon Tetrachloride	0	0	0	8.8	0	" " " "	5
4-04-010-15	Standing-Chloroform	0	0	0	11.0	0	" " " "	5
4-04-010-19	Standing-1,2-Dichloroethane	0	0	0	4.4	0	" " " "	5
4-04-010-26	Standing-Ethylacetate	0	0	0	4.4	0	" " " "	5
4-04-010-28	Standing-Ethyl Alcohol	0	0	0	1.4	0	" " " "	5
4-04-010-39	Standing-Methyl Alcohol	0	0	0	1.9	0	" " " "	5
4-04-010-42	Standing-Methylene Chloride	0	0	0	16.1	0	" " " "	5
4-04-010-43	Standing-Methyl Ethyl Ketone	0	0	0	3.7	0	" " " "	5
4-04-010-44	Standing-Methylmethacrylate	0	0	0	1.9	0	" " " "	5
4-04-010-50	Standing-Isopropyl Alcohol	0	0	0	1.6	0	" " " "	5
4-04-010-55	Standing-1,1,1-Trichloroethane	0	0	0	8.4	0	" " " "	5
4-04-010-56	Standing-Trichloroethylene	0	0	0	5.5	0	" " " "	5
4-04-010-58	Standing-Vinyl Acetate	0	0	0	4.7	0	" " " "	5
Variable Vapor Space (Petrochemical)								
4-04-011-01	Working-Acetone	0	0	0	3.8	0	1000 gal. throughput	3
4-04-011-02	Working-Acrylonitrile	0	0	0	1.7	0	" " "	3
4-04-011-03	Working-Carbon Tetrachloride	0	0	0	4.8	0	" " "	3
4-04-011-04	Working-Chloroform	0	0	0	6.7	0	" " "	3
4-04-011-05	Working-1,2-Dichloroethane	0	0	0	2.2	0	" " "	3
4-04-011-06	Working-Ethylacetate	0	0	0	2.2	0	" " "	3
4-04-011-07	Working-Ethyl Alcohol	0	0	0	0.62	0	" " "	3
4-04-011-08	Working-Methyl Alcohol	0	0	0	1.0	0	" " "	3
4-04-011-09	Working-Methylene Chloride	0	0	0	10.0	0	" " "	3

REVISED SCC LISTINGS

Floating Roof Standing Petrochemical (cont.)	Source	Part	SO_x	NO_x	HC	CO	Units	Action
4-04-011-10	Working-Methyl Ethyl Ketone	0	0	0	1.9	0	1000 gal. throughput	3
4-04-011-11	Working-Methylmethacrylate	0	0	0	0.68	0	" " "	3
4-04-011-12	Working-Isopropyl Alcohol	0	0	0	0.68	0	" " "	3
4-04-011-13	Working-1,1,1-Trichloroethane	0	0	0	4.8	0	" " "	3
4-04-011-14	Working-Trichloroethane	0	0	0	2.6	0	" " "	3
4-04-011-15	Working-Vinyl Acetate	0	0	0	2.5	0	" " "	3

REVISED SCC LISTINGS

Tank Cars/Trucks Loading	Source	Part	SO_x	NO_x	HC	CO	Units	Action
4-06-001-01	Submerged-Normal Gasoline	0	0	0	5	0	1000 gal. transferred	3
4-06-001-02	Submerged-Normal Crude	0	0	0	3	0	" " "	3
4-06-001-03	Submerged-Normal JP-4	0	0	0	1.5	0	" " "	3
4-06-001-04	Submerged-Normal Jet Kero	0	0	0	0.02	0	" " "	3
4-06-001-05	Submerged-Normal Dist No. 2	0	0	0	0.01	0	" " "	3
4-06-001-06	Submerged-Normal Resid No. 6	0	0	0	0.0001	0	" " "	3
4-06-001-25	Splash-Normal Gasoline	0	0	0	12	0	" " "	3
4-06-001-26	Splash-Normal Crude	0	0	0	7	0	" " "	3
4-06-001-27	Splash-Normal JP-4	0	0	0	4	0	" " "	3
4-06-001-28	Splash-Normal Jet Kero	0	0	0	0.04	0	" " "	3
4-06-001-29	Splash-Normal Dist No. 2	0	0	0	0.03	0	" " "	3
4-06-001-30	Splash-Normal Resid No. 6	0	0	0	0.0003	0	" " "	3
4-06-001-50	Submerged-Balance Gasoline	0	0	0	8	0	" " "	3
4-06-001-51	Submerged-Balance Crude	0	0	0	5	0	" " "	3
4-06-001-52	Submerged-Balance JP-4	0	0	0	2.5	0	" " "	3
4-06-001-53	Submerged-Balance Jet Kero	0	0	0	0.03	0	" " "	3
4-06-001-54	Submerged Balance Dist No. 2	0	0	0	0.02	0	" " "	3
4-06-001-55	Submerged-Balance Resid No. 6	0	0	0	0.0002	0	" " "	3
4-06-001-75	Splash-Balance Gasoline	0	0	0	8	0	" " "	3
4-06-001-76	Splash-Balance Crude	0	0	0	5	0	" " "	3
4-06-001-77	Splash-Balance JP-4	0	0	0	2.5	0	" " "	3

REVISED SCC LISTINGS

Tank Cars/Trucks - Loading (cont.)	Source	Part	SO_x	NO_x	HC	CO	Units	Action
4-06-0001-78	Splash-Balance Jet Kero	0	0	0	0.03	0	1000 gal. transferred	3
4-06-001-79	Splash-Balance Dist No. 2	0	0	0	0.02	0	" " "	3
4-06-001-80	Splash-Balance Resid No. 6	0	0	0	0.0002	0	" " "	3
4-06-001-99	Other-Specify						" " "	

Delete all other 4-06-001 Classifications

REVISED SCC LISTINGS Continued

Marine Vessels	Sources	Part.	SO_x	NO_x	HC	CO	Units	Activity
4-06-002-01	Loading Clean Ships-Gasoline	0	0	0	1.3	0	1000 gal transferred	3
4-06-002-02	Loading Dirty Ships-Gasoline	0	0	0	2.5	0	" " "	3
4-06-002-03	Loading Clean Barges-Gasoline	0	0	0	1.2	0	" " "	3
4-06-002-04	Loading Dirty Barges-Gasoline	0	0	0	3.8	0	" " "	3
4-06-002-05	Loading General-Crude	0	0	0	1.0	0	" " "	3
4-06-002-06	Loading General-JP-4	0	0	0	0.5	0	" " "	3
4-06-002-07	Loading General-Jet Kero	0	0	0	0.02	0	" " "	3
4-06-002-08	Loading General-Dist. No. 2	0	0	0	0.005	0	" " "	3
4-06-002-09	Loading General-Resid No. 6	0	0	0	0.00004	0	" " "	3
4-06-002-25	Transit Gasoline	0	0	0	3	0	" " "	3
4-06-002-26	Transit Crude	0	0	0	1	0	" " "	3
4-06-002-27	Transit-JP-4	0	0	0	0.7	0	" " "	3
4-06-002-28	Transit-Jet Kero	0	0	0	0.02	0	" " "	3
4-06-002-29	Transit-Dist. No. 2	0	0	0	0.005	0	" " "	3
4-06-002-30	Transit-Resid No. 6	0	0	0	0.00003	0	" " "	3
4-06-002-99	Other Specity	0		0	0	0	1000 gal transferred	3

Delete all other 4-06-002

REVISED SCC LISTINGS Continued

Underground Gasoline Storage	Source	Part.	SO_x	NO_x	HC	CO	Units	Activity
4-06-003-01	Splash Loading		No Change					
4-06-005-02	Sub Load-Uncont.							
4-06-003-03	Sub Load-Opn Sys.							
4-06-003-04	Sub Load-Cls Sys.							
4-06-003-05	Unloading							
4-06-003-99	Specify							
Fill Vehicle Gas Tank								
4-06-004-01	Vapor Disp. Loss	0	0	0	9.0	0	1000 gallons pumped	4
4-06-004-02	Liq. Spill Loss	0	0	0	0.7	0	" " "	*
4-06-004-99	Other Specity	0	0	0		0	" " "	*